# Final Report

# Applying External Corrosion Direct Assessment (ECDA) In Difficult-to-Inspect Areas

**DTRS56-05-T-0003**

To

**U.S. Department of Transportation**

**Pipeline and Hazardous Materials Safety Administration**

March 2007

# Final Report

# on

# Applying External Corrosion Direct Assessment (ECDA) to Difficult to Inspect Areas

**Prepared for**

## US Department of Transportation
## Pipeline and Hazardous Materials Safety Administration

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**by**

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**14. ABSTRACT**

This project supports development of the ECDA process through evaluation of technology that has evolved since 2002 to fill the gaps that existed then. The objective was to assess the viability of tools that have evolved since the consensus of "difficult to inspect" areas was formulated for RP0502 as approved in 2003. Difficult-to-inspect segments included: cased crossings, and pipelines traversing arid, rocky, or hard-pan clay, or situated under pavement or concrete in scenarios. Consideration also was given to multiple lines lay in one right-of-way (RoW), and high voltage alternating current fields over or adjacent to the RoW. The deliverable was as an assessment whether ECDA can be feasible and effective in such areas. The results reflect evaluation of ~165 km of difficult-to-inspect segments, including evaluation of more than 60 crossings through work for two major pipeline operators. The focus was on three tools: pipeline current mapper (PCM), alternating current voltage gradient (ACVG), and long range guided wave ultrasonic technology (LRGWUT).

A broad range of conclusions and recommendations follow the discussion section of the report for those interested in the details. Suffice it here to highlight the major points, as follows. AC-based technologies (PCM and ACVG) performed well throughout the difficult to inspect segments. While complications developed where multiple lines and/or high voltage alternating current fields exist over or adjacent to the lay in one RoW, changes in the field practices and data processing resolved them. Recent evolution of LRGWUT and the analysis and interpretation of their results make this technology viable and broadly useful in ECDA applications. The qualifications and experience from the field to the office are absolutely critical with respect to the success or failure of the ECDA process.

**15. SUBJECT TERMS**

External corrosion direct assessment (ECDA), difficult to inspect, NACE RP0502, pipeline current mapper (PCM), alternating current voltage gradient (AACVG), long range guided wave ultrasonic technology (LRGWUT), corrosion integrity management

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# Executive Summary

The present project was initiated to support the further development of the ECDA process through evaluation of technologies that have evolved since 2002, in part to fill the gaps that existed then. This project evaluated ECDA over a range of difficult-to-inspect areas, which lead to suggestions and/or insights to make the ECDA process broadly feasible in such areas so operators have more complete and effective ability to manage the integrity of their entire pipeline system.

The objective was to assess the viability of tools that have evolved since the consensus for "difficult to inspect" areas was formulated for RP0502 as approved in 2003. Difficult-to-inspect pipeline segments that were considered included: cased crossings, and pipelines traversing arid, rocky, or hard-pan clay, or situated under pavement or concrete in scenarios. Consideration also was given to cases where multiple lines lay in one right-of-way (RoW), and high voltage alternating current fields exist over or adjacent to the RoW.

The deliverable was as an assessment whether ECDA can feasible and effective in such areas. The results reflect evaluation of ~165 km of difficult-to-inspect segments, including evaluation of more than 60 crossings through work for two major pipeline operators. The focus was on three tools: pipeline current mapper (PCM), alternating current voltage gradient (ACVG), and long range guided wave ultrasonic technology (LRGWUT) – as these were deemed the best candidates to address the above listed scenarios.

A broad range of conclusions and recommendations follow the discussion section of the report for those interested in the details. Suffice it here to highlight the major points, as follows:

- The AC-based technologies (PCM and ACVG) performed well throughout segments with cased crossings, arid, rocky, or hard-pan clay, for pipelines situated under pavement or concrete.
- Complications developed where multiple lines lay in one right-of-way (RoW), and/or high voltage alternating current fields exist over or adjacent to the RoW. However, with appropriate changes in the field practices and in data processing these areas also can be addressed.
- The combination of PCM and ACVG correctly identified the presence and severity of coating faults 96 percent of the time in scenarios where DC-based indirect inspection tools were largely ineffective. Even so there were results that point to high-value modifications to these AC-based tools.
- For cased crossings where the AC-based tools are used in conjunction with LRGWUT, the results indicate that the ACVG procedure and data interpretation criteria with respect to ACVG electrolytic contact estimates should be re-evaluated.
- The recent evolution of LRGWUT and the analysis and interpretation of their results shows significant improvement in this technology – making it viable and broadly useful in ECDA applications. However, in contrast to some tools the need for competent, experienced equipment operators and analysts and broader anomaly-data libraries are success factors.
- LRGWUT has potential utility as a surrogate for direct examination in areas where access or other reasons preclude digging to assess condition. The data developed for the tools

used was very good, however further validation is necessary to more definitively assess the capability and reliability of LRGWUT in such applications.

- The qualifications and experience of operator management, and the contractor and his personnel from the field through the office are absolutely critical with respect to success or failure of the ECDA process – which becomes even more critical for difficult-to-inspect areas.

# Background

The challenge of efficiently and safely operating the natural gas and hazardous liquid transmission system in the US has existed since pipelines were recognized as the best way to transport hydrocarbons. This project was one of four concurrent activities completed under a consolidated program designed to improve the integrity of the pipeline infrastructure in the U.S.

This project was directed at the Government's requirements for **Integrity Management Plans** (IMPs) incorporated through recent changes to the Code of Federal Regulations (CFR) Parts 192[(1)*] and 195[(2)], respectively, for gas and hazardous liquids pipelines. These requirements currently apply to segments of pipeline systems located within high consequence areas (HCAs) and unusually sensitive areas (USAs). Anticipating this regulatory action industry committees also were actively developing pipeline integrity related standards. This included an API committee that developed integrity criteria for hazardous liquids pipelines that was issued as API 1160[(30)]. The API effort was closely followed by an ASME committee effort underpinned by the Interstate Natural Gas Association of America (INGAA) who developed a technology-based approach for integrity management. This was issued as a non-mandatory supplement ASME B31.8S[(4)]. Likewise, a technology-base developed by INGAA led to NACE Task Group 041, which formed to prepare an external corrosion direct assessment (ECDA) practice that became NACE RP0502-2002 – the standardized methodology to conduct ECDA.

While developing the structure and requirements of a high-level IMP that underlies the recent legislation was a significant effort, the real challenge lies in their successful implementation. Within the operations of each company, inspectors must concur that the requirements of the plan have been met. Because modern construction practices and materials when coupled with quality controls limit material, fabrication, and construction defects, and the effects of service and time have not yet become a factor, developing and auditing IMPs is easy for newer pipelines. In contrast, for existing systems made with vintage steels and construction practices that have been in service for some time, such is not the case. Inspectors must be able to track the efforts of the pipeline engineer and agree that the technologies used and their results meet the objectives of the IMP. Tools are required to assess integrity, and criteria that establish their effectiveness are central to this process. To assist with this, both API 1160 and ASME B31.8S provide guidance and criteria. For example, B31.8S identifies 21 integrity threats that must be considered to comply with the regulatory requirements for an IMP.

Historically, pipeline integrity assessment evaluation was based on the results of pressure testing and in-line inspection (ILI). It was recognized that pressure testing and ILI tools had technical strengths and also limitations. More importantly, for some pipelines ILI is not plausible without significant rehabilitation simply to accommodate the tool in the mainline, but even then some segments like "crossovers" remained unpiggable. It followed that an alternative to these technologies was needed. Other integrity assessment methods were evaluated to realize the objective of effective pipeline integrity management. This resulted in an alternative integrity assessment concept that became known as "direct assessment" (DA), although the wording included "other methodologies" to accommodate new integrity assessment technologies that may

[*] Numbers in superscript parenthesis refer to the list of references at the end of this report.

be developed in the future. With this history, hydrotesting and/or ILI served as benchmarks by which to judge the effectiveness of DA or other new technologies. Accordingly, the evolution of the DA technologies and practices included requirements that demonstrate validity as the basis to effectively implement DA and requirements to track effectiveness to ensure the IMP functions throughout each HCA.

A four step structure evolved for direct assessment providing for a systematic application of various above ground inspection methods for more effective integrity assessments. Thus, DA is a ***"Process."*** DA was developed as a process with internal checks and balances designed to ensure that all users follow a consistent methodology, which incorporates validation. Thus, all four steps must be properly completed and documented to be considered valid for IMP applications. One of its major strengths is the feasibility determination that is included in the pre-assessment (first) step, which assesses if DA is suitable or not for each specific pipeline segment. In the event that DA feasibility cannot be established, the process directs the user to other integrity assessment methods.

ECDA is a subset of the overall direct assessment concept focused on external corrosion that is one of the defined pipeline threats. Other direct assessment methodologies for internal corrosion and stress corrosion cracking have been developed but are not a subject of this report.

External corrosion direct-assessment (ECDA) technology is one DA approach suggested by the industry in response to the just noted regulations, being designed to characterize the condition of pipelines specifically targeting unpiggable segments. ECDA became an industry consensus document in the form of NACE RP 0502(5), which occurred in 2002. This recommended practice (RP) provides the methods and guidelines for conducting ECDA on pipelines that may be applied where an external corrosion threat has been identified. Some of the tools and techniques that underlie ECDA have been used for years by pipeline operators to infer the integrity of their systems. With the advent of RP0502, the sometimes inconsistent application and interpretation of these tools and techniques becomes codified, leading to consistent auditable outcomes.

Consistent with the DA process, RP 0502 defined a four step ECDA process for conducting DA thereby providing for a systematic application and interpretation of the various above ground inspection methods for more effective integrity assessment. As balloted ECDA was presented as a process with internal checks and balances that were designed to ensure all users implement a consistent methodology. Because ECDA is a defined process, all four steps must be properly completed and documented to be considered valid for use in IMPs. Pre-assessment is critical to success, as it evaluates ECDA feasibility for each ECDA region, and directs the user toward other integrity assessment methods including pressure testing and ILI in the event the **process** is not **feasible**.

As approved in 2002, it was recognized that the ECDA process provided in NACE RP0502 was not supported by the tools needed to succeed in all possible situations where an ECDA-based pipeline integrity assessment might be the preferred integrity assessment option. Due to the established performance characteristics and application limitations of the available above ground inspection tools, some segments of a particular pipeline could be difficult or impossible to inspect with such methods. This would lead to a situation where a complete integrity assessment could not be performed using ECDA – a situation not acceptable to pipeline operators or to regulatory agencies. In NACE RP0502-2002, such situations were generally considered in terms of a requirement to establish ECDA feasibility in the pre-assessment step described in NACE RP0502. If conditions were found to exist that either made indirect inspection tools difficult to apply or precluded their application entirely, then the ECDA process was not considered to be feasible or the allowance for "other" methods of integrity assessment could be invoked provided the "appropriate confidence level" could be established.

Cases where the feasibility of ECDA in a potential ECDA region was limited by the adequacy of available DC-based aboveground tools were termed "**difficult-to-inspect**"[1]. These scenarios were identified by a consensus of those that practiced close interval surveys (CIS), direct-current voltage gradient (DCVG), Pearson surveys, etc, which comprised the tools that underlay the second step in the DA process – indirect inspection. Unfortunately, with the definitions of NACE RP0502 much of the mileage in HCAs can be considered "difficult to inspect". Given this was a **technology-driven gap** related to tools to effectively implement ECDA, technologies were subsequently developed and/or adapted to bridge this gap. In turn, this leads to the need to assess their utility, to facilitate broader more effective use of ECDA – and the redefinition of difficult-to-inspect in the next ballot-cycle for NACE RP0502. This project was directed at utility of ECDA tools and technologies in difficult-to-inspect areas, to evaluate or demonstrate their utility in such applications.

One of the more prevalent and difficult to inspect conditions specifically cited in RP0502 was cased pipeline crossings. A second equally prevalent and difficult to inspect condition involved arid or rocky regions, while a third involved segments under concrete or pavement. When NACE RP0502 was balloted for its 2002 release, there were no above ground inspection tools widely considered by the industry to be applicable to the inspection of pipeline within cased crossings. While in concept the arid regions could be addressed by "watering" the right-of-way (RoW), the amount of water to ensure an effective indication of the coating condition was impractical – particularly for hard-pan clay. Likewise, both concrete and pavement could be addressed by boring access holes, which also needed to be "watered" so faced the effectiveness concern, and the concern for practicality in crossing a major freeway.

In addition to the concerns on the effectiveness of DC-based above ground inspection tools, each of the above noted scenarios brings difficulty in implementing the third step in ECDA – direct examination. Digging a casing under a major freeway is even less practical than hole-boring one, which makes clear the need for methods to conduct direct examination of pipe where access is limited. This raises additional ECDA feasibility issues with respect to any pipeline for which access is limited (under a canal, river, or lake) or impractical (under freeways etc.). As part of this project, "other" methods were considered, including long range guided wave ultrasonic inspection (LRGWUT) as a surrogate for the requirements the ECDA direct examination step.

Once such tools are evaluated, a consensus will develop to incorporate them into RP0502, thus broadening the capability to characterize **pipeline condition**. Only then can the process be validated through direct examination step for such difficult-to-inspect areas, and **system integrity** and the **re-inspection interval** be reliably established for all the defects that otherwise remain un-dug according to an ECDA-based **integrity assessment process**.

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[1] Few operators would risk use of unproven technology, much less consider their use in difficult-to-inspect areas within HCAs. Thus, the focus was difficult-to-inspect areas without the concurrent requirement of an HCA.

# Introduction

NACE Standard Recommended Practice RP0502, "Pipeline External Corrosion Direct Assessment Methodology" (ECDA) was first issued in 2002[5]. It represented the first pipeline industry attempt to codify a process directed at integrity management based on the uniform application of various above ground inspection methods, many of which had been in use by the pipeline industry for years. ECDA has since been recognized within recently mandated regulatory actions that incorporated integrity management requirements into CFR 192 and 195.

Due to the known performance characteristics and application limitations of the aboveground inspection tools available in 2002, some potential ECDA regions of a particular pipeline could be difficult or impossible to inspect with such methods. Because major segments of the HCAs – which were the focal point for ECDA-based integrity assessment – lay within such hard-to-inspect segments, there was need for new technology to overcome such limitations.

The present project was initiated to support the further development of the ECDA process through evaluation of technologies that have evolved since 2002, in part to fill the gaps that existed then. It also considers issues that may indicate the need for changes in RP0502 that will be considered in the near future by NACE TG 041. The results developed herein reflect not only work supported by this project but also the results of ECDA evaluation programs conducted by Battelle and others[7-14], which have increased industry's knowledge base. This project extends this knowledge base through the experience gained in the use of new or improved tools whose purpose was facilitate broader effective use of the ECDA process to specific sites considered to be difficult-to-inspect by the industry.

The outcome is an independent assessment and/or verification of ECDA over a range of difficult-to-inspect areas, leading to development of suggestions or insights to make the ECDA process broadly feasible such that operators have a sound basis to make integrity assessment decisions.

The rationale for this program is to take potentially difficult application situations and work toward improving the industry's confidence about implementing ECDA based integrity management programs in all areas of their systems. Without this program, or similar efforts conducted by individual pipeline operators, the industry's ability to confirm the actual ECDA effectiveness in difficult to inspect locations and thus the use of the ECDA process as part of a comprehensive IMP becomes problematic. Like other integrity assessment methods, the ECDA process will continue to evolve and improve with time through more frequent and consistent applications. This report could serve as an aid in facilitating such development.

# Objective, Approach, Scope, and Benefits

The integrity management plan rules promulgated in CFR 192 and 195 along with the required completion dates for mileage in HCAs sparked interest in methods for conducting integrity assessment including ECDA. As noted above, gaps involving difficult-to-inspect regions are being bridged that could broaden the utility of ECDA-based integrity assessment.

The objective was to extend the information base that can be used to assess the effectiveness of ECDA at sites considered to be difficult-to-inspect as defined by the industry. This project specifically targets pipeline within cased crossings, or traversing arid, rocky, or hard-pan clay, or situated under pavement or concrete. The intended outcome was to provide an independent assessment whether ECDA can realistically be applied in such areas. This could come in the form of "yes" where the evidence is clear-cut, or entail suggestions or modification of traditional procedures for application of some above ground inspection tools and possibly offer improved procedures applicable to such locations. Such results will benefit ECDA applications so operators will have a more technically sound basis to make integrity decisions based on ECDA data.

The approach was empirical, relying on quantitative evaluation of viable but largely unproven tools in difficult ECDA applications, to assess effectiveness and develop industry confidence moving as appropriate toward industry and regulatory acceptance of the ECDA for use in IMPs.

By contract, including reference to the cost-share companion project this project considered the scope presented in Table 1, with the results presented later organized into sections that cover each task, or occasionally a group of tasks.

**Table 1. Work scope for this project, including coverage by the cost-share projects**

| Task | Deliverable / Milestone |
|---|---|
| CS1 | Support from industry for prioritizing problem areas |
| CS2 | Agree on selection of sites |
| CS3 | Assist with indirect measurements |
| CS4 | Complete field excavations for direct examination |
| CS5 | Review data analysis and reports |
| 1 | Problem areas prioritized |
| 2 | Problem areas selected |
| 3 | Standardized indirect inspection protocol complete |
| 4 | Direct examination data collection complete |
| 5 | Compile all field data |
| 6 | Reporting |

Benefits anticipated from meeting the objective include:

- Enhanced system safety through broader coverage by ECDA-based integrity assessment made effective where it was previously not considered to be feasible. Such is achieved through rehabilitation of coating fault locations where future integrity problems might occur absent ECDA-driven integrity management.

- Improved industry standardization of solutions to ECDA applications in difficult-to-inspect areas that otherwise remain a source of fragmented inspection methodologies. More standardized methods applied to such areas would begin a cycle of industry wide analyses to determine if the methodology was providing the desired results.
- Continued development of technology and tools promoted by the recognition that “other” developments would be accepted if shown viable. This could motivate further development of aboveground indirect inspection tools, as well as strengthen integrity management through use of a broader database for data integration and alignment.
- More certain integrity assessment through the continued evolution of LRGWUT as a surrogate for “direct” examination. This could enhance certainty for all scenarios for which access is impractical.

# Work Plan, Report Organization, and Deliverables

The report considers data developed from two separate ECDA projects, which are referred to herein in terms of the pipeline companies involved denoted Operator A and Operator B. These operators and their ECDA projects[2] are briefly described as follows:

- Operator A is a major natural-gas pipeline company that because of their system's location has a large number of cased crossings to maintain, which is complicated as they cross heavily traveled roads. Consequently, one of their primary interests in the use of ECDA is focused on pipeline segments within cased crossings. Cased crossings are common throughout the pipeline industry such that the outcome of the work for this operator has industry wide impact. Cased crossings are noted as difficult to inspect in Table 2 of NACE RP0502.

  A total of 117 casings were considered with results developed via selective excavations, ILI, and two currently available LRGWUT tools. As such, while only one operator's results are addressed the coverage is very comprehensive.

- Operator B is also a major oil and gas exploration and development company. Their pipeline system consists of both oil and gas transmission pipelines that traverse a large diverse geographic area, much of which comprises difficult-to-inspect areas. A general ECDA project for this operator was conducted by Battelle that was applied to 146 miles (235 km) of their system.

  Work for this operator included several classes of difficult-to-inspect areas from the list identified in Table 1 and the footnotes for Table 2 of NACE RP0502. Much of this effort focused on ECDA through arid soil and hard-pan clay, with some paved-over and concrete covered areas, parallel lines, and stray-current areas considered along with cased road/rail and stream crossings. Again, while only one operator's results are addressed the coverage is comprehensive, as about 70-percent of the 146 miles (235 km) involved difficult-to-inspect ECDA regions.

The work plan for this project included the following four major elements:

1. Identify specific conditions and locations of concern to pipeline operators where the current NACE ECDA process is considered to be difficult-to-inspect and utilize industry committees to prioritize them. Identify candidate ECDA indirect inspection procedures that could potentially mitigate such difficulties.
2. Identify and select sites that meet the criteria in the prioritized list and conduct indirect inspections according to the identified procedures at locations that would be excavated for direct examination.
3. Correlate the indirect inspection with the direct examination data.

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[2] Consideration of emerging technology brings with it risks that limit their consideration, which complicates any project whose approach is predicated on the use of such technologies. The two operators that became involved with these tool-trials did so primarily because their systems exposure to difficult-to-inspect areas was sufficient that the risk associated with continued operation absent condition monitoring was offset by the risk associated with the trial runs.

4. Analyze and validate the results to determine the effectiveness of the ECDA process used and identify difficulties or issues that resulted from the process application.

While Table 1 is effective in organizing the scope in terms of activities completed as cost-share as compared to the PHMSA effort, it is ineffective for reporting because of the nature of the field work done to meet the objective of this project. Within the context of the above four elements and differences in the field work, the results are best reported on an operator-specific basis for the seven tasks as indicated in Table 2. Details in support of these tasks are presented in the appendices. Appendices A through D present details of the tools and procedures used in the work reported, while Appendices E and F summarize details of the LRGWUT done for Operator A.

**Table 2. Task description and reporting framework**

| Task | Activity |
|---|---|
| 1 | Gain industry agreement regarding identification of existing/potential difficult to inspect areas |
| 2 | Prioritize difficult to inspect areas |
| 3 | Prepare standardized indirect inspection protocol and assist with indirect measurements |
| 4 | Complete field direct examination and data collection |
| 5 | Review indirect inspection and direct examination data and reports |
| 6 | Compile all ECDA data and prepare final report |
| 7 | Submit quarterly and final reports |

Tasks CS1 and CS2 in Table 1 were accomplished in concert with the US industry through participation in industry ECDA meetings. These meetings resulted in a prioritized list of difficult-to-inspect areas, which served as a guide for selecting pipeline industry ECDA programs to be included in this project. Details pertaining to Task CS2 and CS3 were addressed with each of the operators during a visit to their facilities. While that dialog was generic in regard to all aspects of the ECDA process as set forth in NACE RP0502 for Operator B, they focused on proposed statistical analysis procedures that would be used to analyze the outcome of the indirect inspection and direct examination data developed by Operator A. As the project progressed, discussions continued regarding the progress and issues that developed during indirect inspections. Task CS4 included a preliminary direct examination and related data review with the operator's subject matter experts (SMEs), and multiple visits to survey and excavation sites. The site visits served to verify that specific aspects of the ECDA process were being addressed consistent with this project's needs, and to observe their field implementation. Task CS5 involved a complete data analysis and compilation, which again involved travel to discuss outcomes and implications with the operator's SMEs. The results of these five activities developed through cost-share funding are presented in the Results section of this report, commingled with work under this project on an operator-specific basis.

There are four major deliverables from this project, as follows:

- Evaluation of recently developed or enhanced tools that directly target difficult-to-inspect areas, including quantitative assessment of viability and validity. Tools covered include PCM, ACVG (A-Frame), and LRGWUT (Gull and Teletest). This deliverable considers cased crossings, arid, rocky, or hard-pan clay, lines under pavement or concrete, and lines under streams. This outcome develops in a "yes/no" format where the evidence is clear-cut, or entails suggestions or modifications as appropriate.

- Enhanced system safety made possible through broader coverage by ECDA-based integrity assessment where it was previously not feasible.
- Improved industry standardization of solutions to ECDA applications in difficult-to-inspect areas. This deliverable will come through updating RP0502.
- Continued development of technology and tools promoted by the recognition that "other" developments are accepted if shown viable. This included continued development of LRGWUT as a surrogate for "direct" examination.

# Results

## Prioritizing Difficult to Inspect Locations

The initial project action described in the above work plan was to review the current RP0502 of "difficult-to-inspect" situations in light of conditions that can be encountered while conducting ECDA to finalize a list of "difficult-to-inspect" areas, and thereafter prioritize that list. Results developed in previous ECDA projects conducted by Battelle and various related industry contacts generated a preliminary list of such conditions. This list was submitted for review and discussion during a joint PRCI/INGAA/GTI/NACE meeting on ECDA held in April, 2005. This meeting was attended by both pipeline operator personnel and inspection services representatives with extensive collective knowledge and experience related to above ground inspection tools and their potential application to pipeline integrity assessment by ECDA.

Battelle's tentative listing of difficult-to-inspect conditions was discussed extensively, and then modified and prioritized resulting in the industry consensus. The modified list reflecting this consensus is shown in Table 3.

Application of ECDA to pipeline segments within cased crossings received broad support as the most significant impediment to achieving a continuous ECDA application on many pipeline systems. Due to perceived project funding limitations, it was agreed that the project should primarily focus on potential industry participants conducting ECDA projects related to the top few higher-priority difficult-to-inspect areas presented in Table 3. However, it was also decided that any identified ECDA project that included any element contained in Table 3 would also receive consideration.

**Table 3. Prioritized ECDA difficult-to-inspect areas**

| Priority | Hard to Inspect Area |
|---|---|
| 1 | Cased crossings |
| | Pipe partially or fully encased in concrete anchors. |
| | Pipe into buildings etc through brick/concrete walls |
| 2 | Pavement or other hard surfaces |
| 3 | Shielding coatings (coating that cause electrical shielding per RP 0502) |
| | Insulated pipelines |
| | Joint coatings (shrink sleeves) |
| 4 | Significant stray current ( HVAC, HVDC etc) |
| 5 | Water/River crossings |
| | Concrete coated pipe/swamp weights |
| 6 | Station piping or other similar complex piping locations |
| 7 | Bare or poorly coated pipelines |
| 8 | Shielding Soils |
| 9 | Deep burial conditions |
| 10 | Multiple, parallel pipelines in the same R-O-W. |
| 11 | Spans |

## Identifying and Selecting Sites

Once the prioritized list was established, an effort began immediately to identify potential pipeline operators and/or contractors conducting ECDA projects that met the hard-to-inspect location criteria established in Table 3. Once they were identified, an assessment was made of the utility of the data and prohibitions on data-release. As this last aspect was a discriminator for some, the requirement was relaxed to admit data absent details as long as the results that could be presented matched the above listed deliverables. Initially, several pipeline operators known to be planning or conducting ECDA projects were identified as potential participants during the above mentioned ECDA meeting held in April, 2005.

The effort to identify potential participants continued throughout this project. The effort was primarily directed toward pipeline operators and contractors that offer indirect inspection and ECDA services to the pipeline industry. In one case, the pipeline operator contacted conducted their own ECDA projects in addition to offering ECDA services to others. Early in the process, a pipeline operator proposing to conduct a large casing ECDA project was identified and agreed to become a participant. This project also included water crossings, which is also an element on the difficult-to-inspect list in Table 3.

Some potential participants were reluctant to participate because they did not want their ECDA data released in any way into the public domain. Others initially agreed to participate but their proposed ECDA projects were either delayed indefinitely, or never initiated. Extended time periods required to obtain the necessary permits needed to obtain site access and related delays were the most frequent schedule problems mentioned. Some potential participants were considered that had recently conducted potentially useful ECDA projects but their scopes were either too limited to permit an effective analysis or their methods and data were not suitable for process and statistical analyses. Later, after DOT audits of pipeline operator ECDA programs began, potential participants with viable projects that initially agreed to participate, in principle, abruptly withdrew. Through industry contacts, it was determined that some potential participants had been part of these DOT audits of pipeline operator's ECDA efforts which were considered to be "contentious" by the operators. This resulted in re-evaluation of their ECDA applications and methods and they also considered any related information or data to be proprietary information. In this latter period the work for Operator B showed promise as it reflected broad coverage of several difficult-to-inspect conditions, although they declined detailed release it was possible to discuss the findings in sufficient detail to meet this project's deliverables.

Taken together, the scope of circumstances considered in the ECDA work for Operator A and Operator B and the level of effort more than met the project's expectations.

## ECDA Process Description

### Operator A

A significant number of Operator A's pipelines are located within congested urban areas which implies that a large number of cased crossings exist within their pipeline system. NACE RP0502 identified casings as a potential problem with respect to completing pipeline integrity assessments using the ECDA process, while Table 3 reinforces that view circa 2005. Because casing inspections are a very important part of successful ECDA implementation along a pipeline, Operator A initiated an effort early on with other pipeline operators to consider the best options for conducting a casing ECDA process. This led to adopting an indirect inspection process utilizing the Pipeline Current Mapper (PCM) supported by the PCM + ACVG[3] (i.e., A-Frame). With this, Operator A included a methodology for comparing the casing-to-soil (C/S) and pipe-to-soil (P/S) potentials as an additional indirect inspection evaluation tool in the casing ECDA process.

Initial procedures were drafted and later refined for application to this project. This included comparisons of the difference between C/S and P/S potentials with respect to the results of the PCM and PCM + ACVG data. A limited number of comparisons were made early in the work to determine if such a comparison added value to the ECDA process. These comparisons indicated that where a significant difference between the C/S and P/S potentials exist, the indirect inspection results (PCM and/or PCM + ACVG) also showed there was no evidence of either a metallic or electrolytic short within the casing. Where the difference between C/S and P/S potential was low, the indirect inspection also indicated a short within the casing. Because all of these initial comparison results were consistent, this methodology was adopted as part of the casing ECDA process indirect inspection step.

Operator A developed a four step process for casing ECDA that is integrated with the overall ECDA process included in NACE RP0502:

- Pre-assessment
- Indirect Inspection
- Direct Examination
- Post Assessment

***Pre assessment***

In addition to the data elements[4] required to complete the pre-assessment step in the overall ECDA process, Operator A also added several additional elements to aid in establishing the feasibility of conducting a long range guided wave ultrasonic (LRGWUT) inspection that is a major component of the direct examination step. Some of these additional data elements included the following list. A more complete list of casing pre-assessment data elements is covered later in the report.

- Depth of cover at casing ends
  - Casing access
  - Type of cover
  - Casing length
  - Details of appurtenances within 100 feet of both casing ends
  - Locations of above/below ground structures within500 feet of casing ends

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[3] Hereafter, ACVG is used synonymously with A-Frame, which name derives from the construct used to deploy the ACVG shoe.

[4] These elements include (1) pipe related, (2) construction related, (3) Soils/Environmental, (4) Corrosion Control, and (5), operational data as required by NACE RP0502.

The first three data elements have been used to determine the casing access feasibility and aid in planning. Note in this regard that the length of the casing is important because LRGWUT methods have specific length limitations (see Appendix C). Details regarding local appurtenances are important for determining the feasibility of implementing LRGWUT and conducting verification excavations. The location of adjacent above and below ground structures can also aid in determining the feasibility of casing access and project planning. It also should be noted that project planning and permitting process delays are frequently major issues in the area served by Operator A. More details concerning LRGWUT methods and limitations are included in Appendix C.

### ***Indirect Inspection***

Operator A's casing ECDA indirect inspection methods include PCM, PCM + ACVG, and the difference between the C/S and P/S potentials. The PCM and PCM + ACVG inspections were performed in accordance with the procedure in Appendix B. The anomaly severity classification guide for indirect inspection results is shown in Table 4. The preferred method of conducting the casing isolation test described in Table 3 involves a direct contact to the casing through a wire at both ends of each casing and to a local CP test station on the pipeline. If direct wires to the casing are not available, the minimum casing isolation test requirement is direct connection to a casing vent and CP test station located at the same end of the casing. CIS data up to the casing end may be substituted if a CP test station is not available. Therefore, Table 4 includes a CIS based severity criteria for that option.

**Table 4. Operator A: Casing indirect inspection anomaly severity guide**

| Inspection Tool | Severe Indication | Moderate Indication | Minor Indication |
|---|---|---|---|
| **Casing Isolation (C/S vs P/S)** | Large difference between C/S and P/S potentials indicate a metallic short | Moderate difference between C/S and P/S potentials indicate an electrolytic short | Minimal difference between C/S and P/S potentials indicate an intermittent electrolytic short |
| **PCM** | Current loss across casing, very little current or signal at opposite casing end. Large amount of signal (10db+) and current (25%+) loss indicate a metallic short. Smaller amounts of signal (10db-) and current (25%-) loss indicate resistance contact. Current and signal loss at either end of casing, indicating metal to metal contact is at end where loss occurs. Contact not at the ends of casing may be indicated by signal and current loss at point of contact on the casing. | Noticeable current loss across casing. Locate signal loss occurs across casing, doesn't return downstream of casing. | No or minimal (less than natural current loss) across casing. Insignificant locate signal loss (5db or less) across casing. Locate signal loss across casing but signal returns to near upstream level downstream of casing. |
| **PCM with A-Frame** | Arrows pointing toward middle of the casing when placed near the ends of the casing. Values of greater than 80 db should be considered metal to metal contacts | Arrows pointing toward middle of the casing when placed near the ends of the casing. Values of less than 80db can be considered an electrolytic short | No Arrows indicated on read out screen when device is placed near each end of the casing |
| **CIS P/S at each end of casing** | Full convergence of on-off reads near casing ends | Partial convergence of on-off reads near casing ends | No convergence of on-off reads near casing ends. |

Tables 5a and 5b illustrate the casing ECDA prioritization criteria applied by Operator A based on the indirect inspection methods that have been adopted. Table 4 applies to casings where direct wire connections extending above ground are available to determine the C/S potential. The criteria in Table 5b are applied in situations where test stations needed to establish the P/S potential are not available and local CIS data must be substituted. The entries in Tables 5a and 5b indicate the severity classification in terms Severe, Moderate, and Minor for the particular inspection method consistent with NACE RP0502, Table 3. The body of Tables 5a and 5b also indicates the direct examination prioritization to be assigned in terms of (I) Immediate, (S) Scheduled, and (M) Monitored.

**Table 5. Operator A Casing ECDA prioritization**

**Table 5a. Direct casing connections available**

| | | Casing Electrical Test | | |
|---|---|---|---|---|
| | | Severe | Moderate | Minor |
| PCM | Severe | I | S | S |
| | Moderate | I | S | M |
| | Minor | I | S | M |
| A-frame | Severe | I | S | S |
| | Moderate | I | S | M |
| | Minor | I | S | M |

**Table 5b. Direct casing connections not available**

| | | PCM | | |
|---|---|---|---|---|
| | | Severe | Moderate | Minor |
| CIS | Severe | I | S | S |
| | Moderate | I | S | M |
| | Minor | I | S | M |
| A-frame | Severe | I | S | S |
| | Moderate | I | S | M |
| | Minor | I | S | M |

## ***Direct Examination***

The main elements of ECDA direct examination procedure for casings include the application of LRGWUT to evaluate the pipeline within the casing and direct visual inspection of the pipeline near the casing ends. In order to provide for a standardized LRGWUT approach/methodology for their casing ECDA applications (and any other LRGWUT application), Operator A prepared a procedure covering the process to be applied. The basic elements of this process specific to the LRGWUT tool included:

- Pre-assessment
- LRGWUT inspection requirements and methods
- Verification of LRGWUT results by direct pipe surface examination
- Post-assessment based on the LRGWUT results

Figure 1 summarizes the eight elements contained in Operator A's LRGWUT inspection process for direct examination of casings. An additional description of the elements contained in the LRGWUT inspection process follows Figure 1, with the numbering system in these paragraphs keyed to the section numbering used in Figure 1.

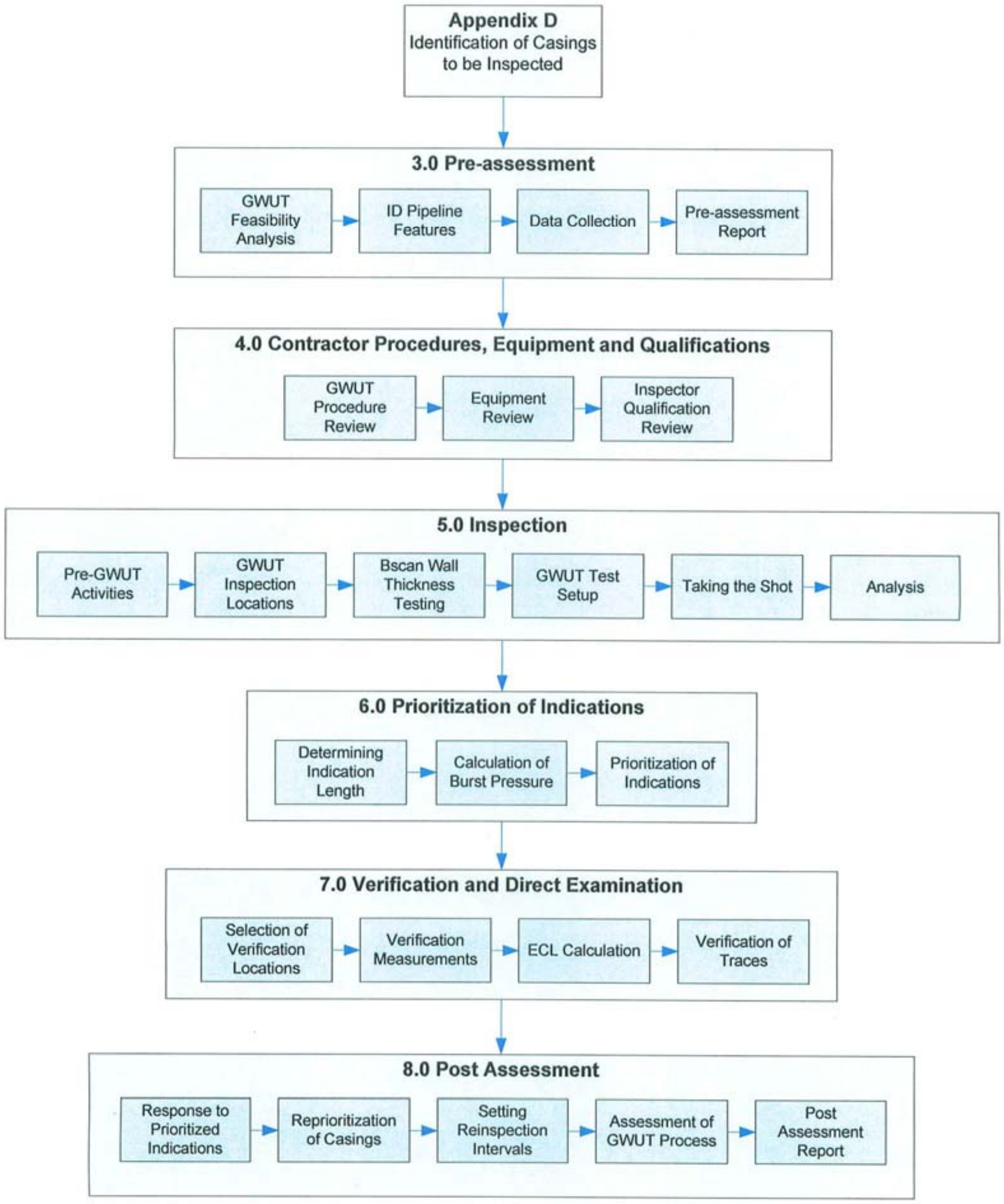


**Figure 1. Operator A Summary description of LRGWUT casing inspection process**

### *Section 3.0 in Figure 1 – Pre-Assessment*

The LRGWUT pre-assessment step is essentially the same as previously described for the generic ECDA. The more specific pre-assessment objectives stipulated in the procedure addresses LRGWUT feasibility, possible access conditions or appurtenances that may limit inspection effectiveness, the pipe length to be inspected, instrument sensitivity level required for an effective inspection and the likelihood and expected characteristics of the metal loss to aid in data interpretation and analyses. A job site evaluation by Operator A personnel is required to verify that LRGWUT is feasible, determine that required excavations can be completed, and conduct an environmental screening procedure. Appurtenances that may interfere with LRGWUT inspections that are located within 100 feet of the casing ends must be identified. This may include valves, flanges branch connections (diameter greater than 25-percent of the pipeline), reducers, and elbows, as such features limit the utility of this technology.

Another element in the pre-assessment step in the LRGWUT procedure is determining the inspection sensitivity required to effectively assess pipeline integrity. This is established by considering the defect size that will survive a hydrotest at the pressures prescribed in Table 6 for the given class locations.

**Table 6. Operator A Test pressure factor**

| Class Location | Test Pressure Factor (Factor X MAOP) | | |
|---|---|---|---|
| | Installed before 11/12/70 | Installed after 11/11/70 | Converted under §192.14 |
| 1 | 1.1 | 1.1 | 1.25 |
| 2 | 1.25 | 1.25 | 1.25 |
| 3 | 1.4 | 1.5 | 1.5 |
| 4 | 1.4 | 1.5 | 1.5 |

The test pressure factor is then input into a LRGWUT sensitivity model along with pipe diameter, wall thickness, and specified minimum yield strength. The output of this model is a pipe rupture curve overlaid on a graph with the LRGWUT sensitivity curves as illustrated in Figure 2. The sensitivity curve values are then adjusted so that the maximum allowable curve intersects the vertical 20-percent circumference line and the pipe rupture curve as illustrated in Figure 2. The required minimum LRGWUT sensitivity is established at the sensitivity level that intersects the minimum detection limit at the vertical line indicating 10-percent of the pipe circumference.

***<u>Section 4.0 in Figure 1 – Contractor Procedures, Equipment, and Qualifications</u>***

Section 4.0 of Operator A's LRGWUT procedure covers the requirements for contractor procedures, equipment and qualifications. The prospective LRGWUT contractor is required to submit a detailed procedure for review by Operator A technical personnel. The procedure must include a general description, inspection limitations, equipment to be used, step-by-step instructions, and documentation of inspection operator qualifications. The contractor must also provide evidence that their equipment is in good condition, has been properly maintained, and is properly calibrated. At the time of this study, two LRGWUT inspection systems were commercially available and acceptable to Operator A. Any other such equipment may only be used with prior approval.

***Section 5.0 in Figure 1 – Inspection***

LRGWUT inspection requirements are addressed in Section 5.0 of Operator A's procedure. Prior to conducting the LRGWUT inspection, the end seal condition is documented. Except for fusion bonded epoxy coatings, all coating within 10 feet of the casing end is removed. Three feet of the casing pipe is also removed from both ends (unless this is not possible) to facilitate direct visual examination of the pipe near the casing ends for LRGWUT verification purposes.

Manual ultrasonic examination of the pipe in the vicinity of the LRGWUT transducer collar mounting location is required by either B-Scan or straight beam ultrasonic methods. This is required because the pipe thickness at this location is used in determining estimated remaining wall thicknesses at anomaly indications within the casing. Requirements are included for positioning, alignment, transducer coupling including pressures for inflatable collars, and methods for performing capacitance tests. The latter test can identify LRGWUT system electrical faults and also to determine that proper transducer coupling exists prior to performing the inspection.

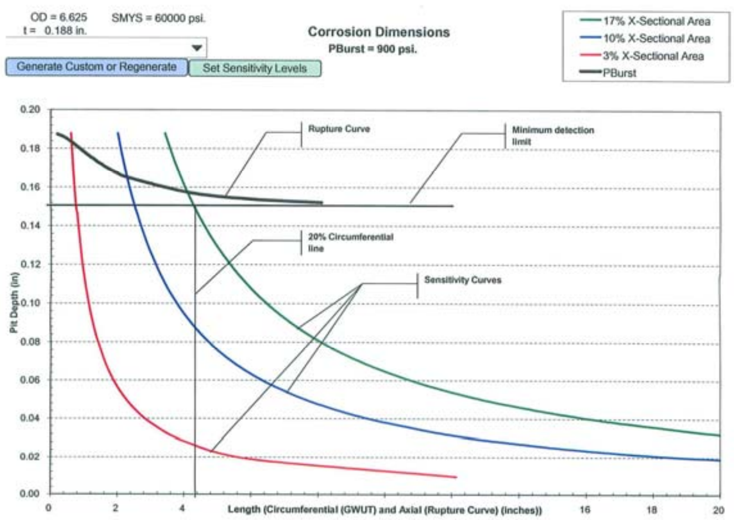


**Figure 2. Operator A Example Pipe Rupture and LRGWUT Sensitivity Curves**

The LRGWUT data collection "shot" begins with input of the required data into the computer which is then used to initiate the data collection sequence. It is also stipulated that no other work on the pipeline that may induce acoustic noise can be done during the shot. An on-site test analysis is then performed immediately following a shot to determine if the data obtained are acceptable. The raw data characteristics including amplitude balance, voltage uniformity between transducer responses, and a capacitance check are also evaluated to assure data quality.

Initial LRGWUT analyses include identification of known pipe features that would have been captured in the data including girth welds, bends etc. A weld Distance Amplitude Curve (DAC) is set to best represent the expected sound attenuation in the pipe. A preliminary estimate of the shot length is made by plotting the "weld" DAC "call" DAC (at a specified sensitivity) with the data to determine the pipe length that can be effectively evaluated before encountering excessive background noise. For estimation purposes, the weld DAC represents 25-percent ECL (estimated cross sectional area loss) the call DAC represents 10-percent ECL. The weld cross sectional area is estimated from measured pipe and girth weld dimensions.

Where LRGWUT identified pipe wall loss features are accessible, they are sized based on ultrasonic test data. Otherwise, the estimated cross sectional area loss (ECL) of the feature is based on the assumed girth weld cross section or a 25-percent ECL.

### *Section 6.0 in Figure 1 – Prioritization of Indications*

Section 6.0 of the LRGWUT procedures addresses the methodology for prioritization of the features detected through consideration of pipe related parameters, estimated wall loss, and a remaining strength evaluation. The initial defect length is estimated from

$$\text{Length} = \sqrt{20 * D * t}$$

where the length is assumed be sufficient to minimize the predicted burst pressure. Other approved length estimates can also be applied. The predicted burst pressure of metal loss areas is then estimated utilizing RSTRENG or other appropriate methods. A safety factor is then calculated as the ratio of the predicted burst pressure to the MAOP with LRGWUT prioritization assigned according to the criteria shown in Table 7.

**Table 7. Operator A LRGWUT Indication prioritization**

| Priority | Pipeline Stress Level at MAOP | | |
|---|---|---|---|
| | At or above 50% SMYS | At or above 30% but less than 50% SMYS | Less than 30% SMYS |
| Immediate Response | Mechanical damage or SF ≤ 1.25 | Mechanical damage or SF ≤ 1.4 | Mechanical damage or SF ≤ 1.7 |
| Scheduled Response | 1.25 < SF ≤ 1.39 | 1.4 < SF ≤ 1.7 | 1.7 < SF ≤ 2.2 |
| Monitored | SF >1.39 | SF >1.7 | SF >2.2 |

It should be noted that LRGWUT methods are unable to determine the size of dents or reliably determine if mechanical damage exists within a dent. Therefore, all features that are described as mechanical damage are assigned an immediate response category.

### *Section 7.0 in Figure 1 – Verification and Direct Examination*

Section 7.0 of Operator A's procedure covers verification and pipe direct examinations to validate the LRGWUT results. This primarily includes exposed pipe surfaces such as areas outside of the casing ends and the pipe within three feet of the removed casing from each end. This examination may also include comparison to known features that have been previously evaluated or ILI data. This examination is to include one feature at each end of the casing and all accessible locations that have been prioritized as immediate according to the criteria described in Table 7. Required feature verification criteria include a detailed description, dimensions including axial length, distance from the transducer collar and an ECL calculation. Verification of the results of the longitudinal and torsional ultrasonic wave response data are also required by comparison to a feature with known dimensions. The difference between the LRGWUT and actual measurement results must be within a specified tolerance that is related to the pipeline MAOP.

Operator A also allows verification direct examinations to be done by conducting a LRGWUT on a "similar" pipeline that has shown to have comparable characteristics based on pre-assessment results. For this purpose, "similar" implies a pipeline with the same coating type and condition, diameter, wall thickness equal to or greater than the pipe be evaluated, and in the same service.

### *Section 8.0 in Figure 1 – Post-Assessment*

Post assessment criteria as applied to LRGWUT based ECDA are covered in Section 8.0 of Operator A's procedure. The objectives include:

- Establish the required response to prioritized indications
- Set response time limits
- Determine re-inspection interval
- Evaluate LRGWUT based ECDA effectiveness

Criteria are provided in the procedure to evaluate the required response to prioritized conditions. The need for reprioritization is based on comparison of the initial prioritization and that determined from direct pipe surface measurements.

Re-inspection intervals are based on the criteria shown in Table 8.

**Table 8. Operator A Re-inspection interval criteria**

| Assessment Method | MAOP at or Above | | MAOP below 30% SMYS |
|---|---|---|---|
| | 50% SMYS | 30% SMYS up to 50% SMYS | |
| ILI, Pressure Test, Direct Assessment | *10 years** | *15 years** | *20 years*** |
| (*) A Confirmatory direct assessment as described in CFR 192, § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval. | | | |
| (**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval. | | | |

The post-assessment process also provides criteria for conducting a detailed review of the LRGWUT based ECDA process. This includes both technical and process adequacy and to determine if process improvements are needed as part of their continuous improvement effort.

## Operator B

An ECDA program was initiated by Operator B as the basis for integrity assessment of non-piggable pipelines within their system. Operator B's pipeline system operates in areas that include a wide range of pipeline environments from very dry, arid soils to wet, swampy areas. Within their operating area, pipelines also cross both rural and urban locales. With respect the difficult-to-inspect areas described in Table 1, this included parallel pipelines, swampy areas, river crossings, road/rail crossings, and pipeline segments adjacent to HVAC electric transmission lines.

Battelle was contracted by Operator B to conduct ECDA in accordance with the requirements of NACE RP0502 and additional ECDA protocols on approximately 146 miles of pipeline of which about 70-percent involved some form of difficult-to-inspect area. Although this ECDA project was more wide ranging, the discussion herein is specific to their difficult-to-inspect areas. In a limited number of locations including a river crossing and a cased rail crossing, ECDA direct examination was conducted by LRGWUT methods as was done by Operator A. A significant portion of Operator B's pipeline system is within an HCA with many of these pipeline segments under concrete or paved surfaces and within cased crossings, which reinforced the need to try other technologies for direct examination such as LRGWUT.

An ECDA protocol was prepared for this project that was based on the requirements of NACE RP0502 and specific characteristics of Operator B's pipeline system. This protocol is included in a somewhat sanitized and adapted format in Appendix D.

### ***Pre-assessment***

Pre-assessment was conducted in accordance with the requirements of NACE RP0502 that included data elements pertaining to the following categories:

- Pipe related
- Construction related
- Soils environment
- Corrosion control, and
- Operational data

Because the overall ECDA process is very data intensive and a properly conducted pre-assessment step is an essential element in its successful completion, a detailed software based data collection tool was developed by Battelle to facilitate data collection. This software was used to populate and organize a database for each pipeline or segment selected for inclusion in the ECDA process. It also provided advice pertaining to ECDA feasibility and contained error traps to identify missing or inappropriate data. It is operable on laptop computers which facilitated field data collection efforts.

Table 9 shows the indirect inspection tool selection adopted for application to Operator B's ECDA project.

**Table 9. Operator B ECDA Indirect inspection tool selection guide**

| Conditions | CIS | DCVG/ACVG | Electro-magnetic (PCM) |
|---|---|---|---|
| Coating holidays | Yes | Yes | Yes |
| Anodic zones on bare pipe | Yes | No | No |
| Near river or water crossings | Yes | Possible | Yes |
| Under frozen ground | No | Yes | Yes |
| Stray currents | Yes | Yes | Yes |
| Shield corrosion activity | No | No | No |
| Adjacent metallic structures | Yes | Yes | Yes |
| Near parallel pipe lines | Yes | Yes | Yes |

| Conditions | CIS | DCVG/ACVG | Electro-magnetic (PCM) |
|---|---|---|---|
| Under HVAC electric transmission lines | Yes | Yes | No |
| Shorted casing | Possible | Possible | Possible |
| Under paved roads | Possible | Possible | Yes |
| Uncased crossings | Yes | Yes | Yes |
| Cased crossings | No | Possible | Yes |
| Wetlands | Yes | Yes | Yes |
| Rock terrain, ledges or backfill | Possible | Possible | Yes |

Considering Operator B's pipeline system and soil characteristics determined from pre-assessment data collection, PCM and ACVG were chosen for indirect inspection surveys because of their developing adaptability to the wide range of soil conditions found in Operator B's pipeline system. Moreover, given the widespread presence of rocky areas, and arid sandy gravel areas or hard-pan clay, the AC-based tools seemed the only viable alternative to the DC-based tools that would prove problematic through these large expanses. PCM serves as the "macro" tool in the AC-based approach, typically being used in 20 to 50 m intervals while ACVG (i.e., A-Frame) complements PCM as the "micro" tool. ACVG provides more definitive data concerning the location and presence of coating faults at sub-meter intervals.

It was found that large geographic areas of Operator B's pipeline system contained very similar soil characteristics that simplified conducting the pre-assessment and minimized the number of regions that had to be considered. Prior experience with these two tools indicated that they were suitable for a majority of indirect inspection scenarios that were present in their system.

***Indirect Inspection***

ECDA indirect inspection involves aboveground surveys to identify and define the coating fault severity or other anomalies, where corrosion activity may have or may be occurring. According to NACE RP0502, two or more indirect inspection tools must be used over the entire length of each ECDA region that provide complementary macro and micro detection with sufficient reliability for the variety of conditions that may be encountered along the ROW. For Operator B, indirect inspection was conducted using the PCM current attenuation "macro" assessment tool at ~20 m intervals with the A-Frame unit used for conducting ACVG voltage gradient "micro" inspections at a meter to sub-meter scale as needed. GPS equipment with 1 meter resolution was used to record coordinates at the measurement locations.

Indirect inspection began with the "macro" level survey. Survey "pin flags" were placed at about 50-meter intervals along the pipeline segment to be surveyed. Alternatively, the intended spacing was approximately walked and marked via GPS coordinates. GPS latitude, longitude, and elevations were then taken at the end of each interval, at road or water crossings, and geographic features. Environmental and public risk factors were also identified and located with the GPS equipment. Often, engineering station numbers were geo-referenced to specific physical features or benchmarks. Once each interval was surveyed, the data were recorded in the equipment used and/or support software.

Where it was necessary to interrupt a continuous survey length because of ROW access issues, the start/stop site GPS coordinates were recorded along with the reason for the indirect inspection gap. Reasons for such gaps included impassable waters, casings, hazardous conditions, and/or other such scenarios.

PCM and ACVG data were analyzed and aligned and then integrated with the database described previously. A severity ranking was then assigned according to Table 10, being typically based on the most conservative criterion.

**Table 10. Operator B ECDA Severity classification table**

| Indirect Tool/Environment | Severity Classification | | |
|---|---|---|---|
| | Minor | Moderate | Severe |
| CIS, aerated moist soil | Small IR dips with on/off potentials less negative than -850 mv | Medium IR dips or off potentials more positive than -850 mv. | Large IR dips or on/off potentials more positive than -850 mv |
| DCVG, aerated moist soil | 1-15% IR drop | 16-35% IR drop | > 36 % IR drop |
| ACVG, aerated moist soil | < 65 db | 65 – 80 db | ≥ 80 to 100 db |
| PCM, electromagnetic survey | Signal attenuation < 10X baseline | Signal attenuation ≥ 10X and ≤ 30X baseline | Signal attenuation > 30X baseline |

Indirect inspection was conducted over the entire length of each region as described with the exception of a cased railroad crossing and a stream crossing. In these locations, above ground PCM and ACVG inspections were conducted up to the ends of the accessible pipeline and the coating condition within the inaccessible area was then inferred from these measurements. Direct examination was then conducted using LRGWUT methods discussed in other sections of this report.

Indirect inspection of Operator B's pipeline system involved several of the difficult-to-inspect locations included in Table 1 including:

- Paved road crossings
- Pipeline crossings
- Parallel to HVAC electric transmission lines
- Pipeline under paved roads
- Multiple pipeline ROW's

The PCM/ACVG complementary indirect tools were selected because they offered significant advantages over other methods with respect to Operator B's operating area and conditions and particularly for pipeline segments under hard surfaces such as asphalt and concrete. With these tools, no special precautions or techniques were required except for wetting the surface to improve equipment response time in some locations.

High voltage AC electric transmission lines are known to induce currents onto pipelines that can affect the magnetic fields being detected by PCM/ACVG equipment. Because the PCM is a "macro" tool used for evaluating longer intervals, it is more susceptible to this effect than the "micro" ACVG tool. Such effects are partially mitigated by the fact that both tools are designed to detect a 4 Hz signal frequency which is lower than the typical AC electric transmission line frequency. In order to overcome any potential interference where pipelines and power lines were parallel for distances greater than about 100 feet, the PCM transmitter was located at decreased intervals (< 1650 feet) to provide a stronger 4 Hz inspection signal. Where the pipeline being evaluated crossed a power line and the affected distance was less than 100 feet, a PCM transmitter interval reduction was not typically required. Where HVAC interference was a problem, increased use of ACVG was beneficial because the interference is less and it yielded more precise survey results.

Where parallel pipelines existed, the PCM/ACVG indirect tools performed well as long as the equipment operator could accurately remain over the proper pipeline. This was done by recording the pipeline position relative to all other pipelines at the survey starting point with the PCM pipe locator function. The survey then proceeds following the signal on the target pipeline. Periodically, scans are made across the RoW to verify the survey is tracking the intended pipeline. Where electrically interconnected pipelines were encountered, the PCM transmitter intervals and survey lengths were decreased.

For this ECDA application, indirect inspection data were collected, assessed, and classified to identify coating faults where corrosion activity could occur. In some cases, indirect inspection tools (i.e., DCVG) have been used to estimate the corrosion activity state. Where such an estimate indicates "inactive", some ECDA users have assumed that no future management is required. No such assumption was made for this project for several reasons. One example is microbiologically induced corrosion (MIC) may be scaled over and "appear" inactive – whereas such corrosion can potentially produce rates well beyond typical dissolution mechanisms and should not be ignored. It follows that the use of a DC-based tool where it can successfully discriminate "active" versus "inactive" corrosion brings little real value in ranking severity or for selecting field dig locations.

### ***Direct Examination***

Indications found during indirect inspection were first prioritized for direct examination according to the following criteria:

- Immediate Action – Indications that likely have ongoing corrosion activity along with a known corrosion history would pose an immediate threat to the pipeline under normal operating conditions.
- Scheduled Action – Indications that could have ongoing corrosion activity, but when coupled with known corrosion history, are not likely to pose an immediate threat to the pipeline under normal operating conditions.
- Suitable for Monitoring – Indications considered to be inactive or having the lowest likelihood of ongoing corrosion activity.

These criteria were established considering the annual physical characteristics of each ECDA region, prior corrosion history, indirect inspection tools used, and the indication severity classification distribution in each region. Indications were prioritized consistent with the requirements in NACE RP 0502 according to the criteria shown in Table 11. A prioritized direct examination list was then created for conducting ECDA work in the field. The scheduled order of excavations and direct examinations depended on the total number of indications, their severity classifications, and prioritization category.

All locations were excavated for direct examination with the exception of a rail crossing and stream crossing where LRGWUT was applied. For this ECDA project, Operator B considered the LRGWUT applications as trial runs to determine if this method would be viable for future ECDA programs. Demonstrating that LRGWUT is a viable technique is particularly interesting to Operator B because a significant portion of their system is within HCAs including many cased crossings and other difficult-to-inspect locations.

**Table 11. Operator B Indirect inspection indication prioritization criteria**

| IMMEDIATE ACTION | SCHEDULED ACTION | MONITOR |
|---|---|---|
| Individual severe indications that are classified as severe by more than one indirect inspection technique. | All remaining severe indications that were not placed in an immediate action category. | All remaining indications. |
| Individual severe indications in regions of moderate prior corrosion. | All remaining moderate indications in regions of significant prior corrosion. | |
| Individual severe indications where the likelihood of ongoing corrosion activity cannot be determined. | Groups of minor indications in regions of severe prior corrosion. | |
| Multiple severe indications in close proximity | | |
| Moderate indications in regions of severe prior corrosion. | | |
| Groups of moderate indications in regions of moderate prior corrosion. | | |
| Any severe or moderate indications if significant prior corrosion is suspected. | | |
| For initial ECDA applications, any location at which unresolved discrepancies have been noted between indirect inspection results. | | |

The required number of direct examination sites in each region was established according to the criteria shown in Table 12. Table 13 is an example of the determination of the number of required excavations based on Table 12 and the requirements contained in NACE RP-0502 for several pipeline segments.

Another element of the direct examination step is re-classification of indications assigned during the indirect inspection step. Knowledge gained from direct examinations is used as a "calibration" of the assumed severity. If direct examinations show differences with the previously assigned severity, then re-classification into a different category and re-prioritization becomes necessary. However, because this was the first ECDA application involving the pipeline segments considered here, no indication downgrading was permitted. It was also found that the overall ECDA application achieved a high level of predictability so such action was not a major issue. Additional discussion regarding overall predictability is contained in the Results section of this report.

***Post-assessment***

Overall, Operator B's ECDA project included about 146 miles of pipeline in several different pipeline systems located throughout their operating area. A large number of indirect inspection indications were found that ultimately resulted in identification of 110 direct examination sites. Twenty of these sites included corrosion that was considered to be significant according to ASME B31G criteria.

**Table 12. Operator B Guidelines to determine the required number of direct examinations**

<table>
<tr><th colspan="5">Anytime ECDA is Being Applied (including when ECDA applied for the first time)</th></tr>
<tr><th colspan="4">And There <u>ARE</u> Identified Indications in the Segment</th><th>And There are <u>NO</u> Indications Identified (In the Segment)</th></tr>
<tr><th>Immediate Action</th><th colspan="2">Scheduled Action</th><th>Suitable For Monitoring</th><td rowspan="4">Perform at least one excavation in the region identified as most likely for corrosion from the Pre-Assessment Step (pick the location in this region identified as the most likely to have corrosion).</td></tr>
<tr><td>All indications that are prioritized as immediate require direct examination.</td><td>If an ECDA Region contains scheduled indications <u>and</u> no immediate indications, then perform an excavation on the most severe scheduled indication in the region.</td><td>If an ECDA Region contains scheduled indications and it contained one or more immediate indications, then perform an excavation on the most severe scheduled indication in the region.</td><td rowspan="3">If an ECDA region contains only monitored indications (i.e., no immediate or scheduled), one excavation is required at the indication most likely to have corrosion.</td></tr>
<tr><td rowspan="2">Note: For a <u>segment</u> where ECDA is being <u>applied for the first time</u>, at least two direct exams are required per region as described directly above (<u>not</u> including the process validation digs shaded in gray below). If the above only results in <u>one</u> total excavation for <u>the entire region</u>, then at least one more examination is recommended at a random location identified as likely for corrosion.</td><td rowspan="3">Note: For a <u>segment</u> where ECDA is being <u>applied for the first time</u>, <u>at least two</u> direct exams are required per region as described directly above (<u>not</u> including the process validation digs shaded in gray below). If the above only results in <u>one</u> total excavation for <u>the entire region</u>, then at least one more examination is required at a random location identified as likely for corrosion.</td><td>OR – If an excavation at a scheduled indication fails ASME B31G Mod. Criteria for Immediate Action <u>and</u> that is deeper <u>or</u> more severe than at an immediate indication, then do at least one more direct examination (i.e. the indication with next highest priority).</td></tr>
<tr><td rowspan="2">Note: For a <u>segment</u> where ECDA is being <u>applied for the first time</u>, <u>two</u> <u>additional</u> direct exams are required per region as described directly above (<u>not</u> including the process validation digs shaded in gray below).</td></tr>
<tr><td>Indications that were reprioritized from immediate to scheduled follow the scheduled guidelines in the Scheduled columns.</td><td colspan="2">Note: For a <u>segment</u> where ECDA is being <u>applied for the first time</u>, <u>at least two</u> direct exams are required per region as described in either column directly above (<u>not</u> including the process validation digs shaded in gray below). If the above only results in <u>one</u> total excavation for <u>the entire region</u>, then at least one more examination is required at a random location identified as likely for corrosion.</td></tr>
<tr><td colspan="5">Process Validation Dig: Perform at least one additional process validation examination at a <u>random location where no indications</u> were detected. This confirms assumptions (for process validation in Post-Assessment).</td></tr>
</table>

| Anytime ECDA is Being Applied (including when ECDA applied for the first time) | |
|---|---|
| **And There <u>are</u> Identified Indications in the Segment** | **And There are <u>no</u> Indications Identified (In the Segment)** |
| **Process Validation Dig**: Perform at least one *additional (to any other one listed in this table)* excavation, randomly selected and categorized as scheduled (or monitored if no scheduled indications exist)in the location identified as most likely for corrosion from the Pre-Assessment Step. This confirms assumptions (for process validation in Post-Assessment). | **Process Validation Dig:** Perform at least one *additional* (to any other one listed in this table) excavation in the *region* identified as most likely to have corrosion from the Pre-Assessment Step (pick the location in this region identified as the most likely to have corrosion). This confirms assumptions (for process validation in Post-Assessment). |

## Table 13. Operator B Examples of required dig numbers using Table 12 and RP 0502-2002

| Case | First Use of ECDA | Number of Indications in SEGMENT | | | No. of Non-Validation Digs Required from Indications (from each priority) | Additional non-validation digs needed when using ECDA the first time | No. Validation Digs (for post-Assessment Step) | Total Digs |
|---|---|---|---|---|---|---|---|---|
| | | Immediate Action | Scheduled Action | Suitable For Monitoring | | | | |
| A | Yes | 4 | 3 | 2 | 4+1+0 | 2 | 2 | 9 |
| B | No | 4 | 3 | 2 | 4+1+0 | NA | 1 | 6 |
| C | Yes | 0 | 4 | 1 | 0+1+0 | 1 | 2 | 4 |
| D | Yes | 1 | 0 | 0 | 1+0+0 | 1 (recommended) | 2 | 4 |
| E | Yes | 0 | 0 | 0 | 0+0+0+1 (at most likely location for corrosion)[1] | 1 | 2 | 4 |
| F | No | 0 | 0 | 0 | 0+0+0+1 (at most likely location for corrosion)[1] | NA | 1 | 2 |
| G | Yes | 0 | 0 | 3 | 0+0+1 | 1 | 2 | 4 |
| H | No | 0 | 0 | 3 | 0+0+1 | NA | 1 | 2 |

Note 1- if no indications are found, then at least one dig is done at most likely location for corrosion based on pre-assessment data.

Post-assessment as the last step in the ECDA process is the culmination of findings from the previous three steps. In accordance with the requirements in NACE RP 0502, Operator B's post-assessment objectives were to establish a rational basis for defect severity assessment, validate the ECDA process and supporting technology, establish the current pipeline integrity level, and define re-assessment intervals for the locations evaluated. Feedback to promote continuous improvement and management-of-change efforts was also an important consideration in this step.

In addition, root cause analyses were also conducted to facilitate viable integrity management plans for locations where the metal loss was greater than 30-percent of the pipe wall thickness. In such locations, corrosion control is a more urgent matter and the root cause results aided in properly focusing Operator B's mitigation resources. In some cases, the coating fault located by indirect inspection was a result of mechanical damage that was related to inadequate depth-of-cover and also indicated a need for increased damage prevention action.

The estimated remaining strength of the corroded areas in terms of predicted failure pressure was determined using the calculation methods described in ASME B31G which are a necessary input for remaining life calculations. Remaining life calculations were conducted in accordance with the ECDA Protocol included in Appendix D and NACE RP0502 with one exception - the safety margin was assumed to be 1.0. This was a conservative assumption that accounted for the possibility of operating the pipeline at pressure near the MAOP which was generally not the case in Operator B's system. Also, the RP0502 default corrosion rate of 0.016 inch/year was assumed because no other site specific corrosion rate data (e.g, buried coupon or linear polarization results) were available and the direct examination results provided evidence that pitting corrosion had occurred. Comparison to other pipeline pitting corrosion data indicated this default corrosion rate is, on average, quite conservative.

# Field Data and Analyses

This section covers the results and analyses of the ECDA programs conducted by Operators A and B. Operator A focused on ECDA techniques that were applied only to cased pipeline crossings. Operator B conducted a more wide ranging ECDA program that included several of the difficult-to-inspect areas included in Table 1. With respect to Operator B, the results and analyses covered herein are primarily directed toward the difficult-to-inspect areas; however, some overall program statistics have also been presented because they also pertain to the difficult-to-inspect locations that were encountered.

## Operator A

In the early stages of Operator A's casing ECDA evaluation program, an analyses process was described by Battelle that utilized the Chi-square test ($\chi^2$) of association of the data arranged in the form of a 2 x 2 contingency table. This tests the hypothesis that a relationship or association exists between the results of two ECDA methods being considered against the hypothesis that no relationship exists. A calculated "p-value" gives a measure of the strength of the association with smaller p-values indicating a greater association. A commonly accepted p-value cutoff criterion is 0.05 for there being an association (with a 95-percent confidence level) between the two ECDA process methods being considered. Specifically a p-value of 0.05 means that if there were in fact no association between the methods and it were possible to recollect the data many times, an apparent association of at least the degree observed in the measured data would occur 5-percent of the time due to random chance. Small p-values indicate that a chance occurrence of this magnitude is rare, thus supporting the hypothesis that there is an association between the methods.

The $\chi^2$ test of association compares the actual cell data counts versus the expected counts determined from the $\chi^2$ statistical distribution. In order for the $\chi^2$ test of association to be a valid statistical test, all cells in a 2 x 2 contingency table should have at least 5 observations. For the data generated by this project, it was found that the ECDA methods being considered all had at least one cell with counts less than 5 and often more. Even where optimal data distributions exist within a contingency table, the $\chi^2$ test is considered to be an approximate method and with minimum required cell counts the approximation is very good and is commonly used. Due to the low cell counts in this application the $\chi^2$ test results were considered to be suspect because basic 2 x 2 table data distribution assumptions were violated. Additional information concerning the $\chi^2$ test is contained in Appendix E

When small cell counts exist, an alternative exact method called "Fisher's exact test" can be applied without such validity concerns. In addition to the $\chi^2$ test, Fisher's test was run for all of the 2 x 2 comparisons that were made. Two statistics are reported from this analysis method; one for a two sided test which tests association in either direction (agreement or disagreement) which compares to the $\chi^2$ test and a right sided test which only considers agreement. Fisher's test relies on probabilities determined using the hypergeometric probability distribution to determine exact p-values.

Operator A's data were organized as two different sets based on the method used for the direct examination step but the indirect inspection methods were the same. One data set included PCM and PCM + ACVG for indirect inspection and prior ILI data (ECDA/ILI data set) was considered as direct examination data. The other data set used the same indirect inspection process but the direct examinations step was conducted by one LRGWUT inspection at some of the casings and in several cases, two LRGWUT inspections using different commercially available systems on the same casing (ECDA/LRGWUT data set). The complete data sets in coded form are shown in Appendix F as Tables F-1 and F-2.

Initial inspection of the ECDA with ILI direct examination showed that the number of electrolytic contacts indicated by the A-Frame indirect inspection data was quite different than the other indirect inspection results. Also, a significant fraction of these A-Frame electrolytic contact results data did not agree with the level of difference between the P/S and C/S potentials. This suggests a possible problem existed with the procedure and/or data interpretation. Furthermore, similar data in the ECDA/LRGWUT data set did not indicate the same trend. Table 14 illustrates the differences between the numbers of suspected contacts considering the indirect inspection results reported in ECDA/ILI data set.

**Table 14. Operator A Indirect inspection suspected contact distribution**

| | PCM/ACVG Suspected Contact | | | |
|---|---|---|---|---|
| | Metallic | | Electrolytic | |
| | PCM | ACVG | PCM | ACVG |
| Number of reported contacts | 4 | 0 | 4 | 16 |

It should be noted that the results shown in Table 14 were obtained from a subset of the total ECDA/ILI data set shown in Appendix F. Of the 58 total results, 32 included both P/S and C/S potentials required to compare ECDA indirect inspection results to the measured potential differences.

Table 15 summarizes the analysis results considering the association between PCM and PCM + ACVG indirect inspection results and the P/S-C/S potential difference and Table 16 summarizes the same comparison except without the A-Frame electrolytic contact results.

**Table 15. Operator A Analysis results – indirect and P/S – C/S potential difference**

| | | P/S – C/S Potential Difference | | |
|---|---|---|---|---|
| | | No Contact | Contact | Total (Actual) |
| Indirect Inspection PCM + ACVG | No Contact | 14 | 0 | 14 |
| | Contact | 14 | 4 | 18 |
| | Total | 28 | 4 | 32 |

**Table 16. Operator A Analysis results – indirect and P/S – C/S potential difference - without indirect A-Frame electrolytic contact**

| | | P/S – C/S Potential Difference | | |
|---|---|---|---|---|
| | | No Contact | Contact | Total (Actual) |
| Indirect Inspection PCM + ACVG (without A-Frame Electrolytic Contact) | No Contact | 24 | 0 | 24 |
| | Contact | 4 | 4 | 8 |
| | Total | 28 | 4 | 32 |

For the data contained in Tables 15 and 16, the calculated Fisher's exact test p-values were 0.113 and 0.002, respectively. These p-values indicate that with all four indirect inspection results included, an association between indirect inspection and P/S-C/S potential is suggested by the data at about the 85-percent level. However, when the indirect inspection A-Frame electrolytic contact results are removed from the analysis as reflected in Table 16, then the presence of an association becomes significant at the 95-percent level. This supported the initial conclusions that the high proportion of A-Frame electrolytic contacts with respect to the other results probably represented a significant number of false positive results which implies possible indirect inspection procedure and/or data interpretation issues existed.

Additional 2 x 2 contingency tables were compiled and analyzed based on the ECDA/ILI data set shown in Appendix F. They considered associations between the ILI results versus five combinations of indirect inspection and P/S-C/S potential differences. The content of these tables is summarized in Table 17. Where comparisons with ILI results have included P/S-C/S potential differences the sample size included only the 32 results where both potentials were recorded. The remainder considered the total ECDA/ILI data set. It should be noted that the ILI only responds to metal loss locations and the indirect inspection indicates possible coating fault locations thus implying the existence of a location that may or may not include metal loss.

**Table 17. Operator A - 2 x 2 Contingency table analysis for ILI and indirect inspection**

| | ASSOCIATION WITH | SAMPLE SIZE | FISHER'S EXACT P-VALUE |
|---|---|---|---|
| In-Line Inspection | P/S-C/S potential difference | 32 | 0.125 |
| | All indirect inspection and P/S-C/S potential difference | 32 | 1.00 |
| | Indirect inspection (without A-Frame electrolytic results) and P/S-C/S potential difference | 32 | 0.250 |
| | All indirect inspection results | 58 | 0.290 |
| | Indirect inspection (without A-Frame electrolytic results) | 58 | 0.500 |

None of the Fisher's exact p-values shown in Table 17 indicate that a significant association between ILI and the other five indirect inspection result combinations exists. All of the Fisher's exact p-values shown in Table 17 indicate some level of association at less than the 95-percent level with the exception of the second row where the p-value is 1.00[5] which indicates that no association exists.

These results tend to support earlier work that suggested that unless pre-assessment indicates a significant pre-existing external corrosion problem, any such association between ILI and ECDA results is unlikely to be significant[(10)]. This result can be confirmed by inspection of the results in Appendix F, Table F-1. Of the 58 total results included, 3 external corrosion defects, and 1 unknown ILI result were reported. Two of the three ILI external corrosion results correspond to indirect inspection data where the only positive indirect inspection result was a suspected A-Frame electrolytic contact that the analyses discussed above have suggested may be problematic. Only one of the three ILI results corresponded to other than an A-Frame electrolytic contact result.

The ECDA/LGRWUT data set was first evaluated to determine if any association exists between the indirect inspection results and difference between the P/S and C/S potentials similarly to the ECDA/ILI dataset evaluations summarized in Tables 15 and 16 above. These analyses were based on a subset of the total ECDA/LRGWUT data set shown in Table F-2 in Appendix F because all data elements did not included both P/S and C/S potentials required for such a comparison.

Tables 18 and 19 are similar to Tables 15 and 16. These tables summarize the analysis results for indirect inspection and P/S-C/S potential difference data from the ECDA/LRGWUT data set.

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[5] The degree of association between the methods being evaluated increases with a decreasing p-value.

**Table 18. Operator A Analysis results – indirect and P/S – C/S potential difference**

| | | P/S – C/S Potential Difference | | |
|---|---|---|---|---|
| | | No Contact | Contact | Total |
| Indirect Inspection PCM + ACVG | No Contact | 23 | 0 | 23 |
| | Contact | 4 | 2 | 6 |
| | Total | 27 | 2 | 29 |

**Table 19. Operator A Analysis results – indirect and P/S – C/S potential difference without indirect A-Frame electrolytic contact data)**

| | | P/S – C/S Potential Difference | | |
|---|---|---|---|---|
| | | No Contact | Contact | Total |
| Indirect Inspection PCM + ACVG (without A-Frame Electrolytic Contact) | No Contact | 25 | 0 | 25 |
| | Contact | 2 | 2 | 4 |
| | Total | 27 | 2 | 29 |

The Fisher's exact p-values for the data in Tables 18 and 19 are 0.037 and 0.015 respectively; both of which indicate a significant association exists (at the 95-percent level) between the indirect inspection results and the difference between the P/S and C/S potentials. These results are essentially consistent with the same analyses for the ECDA/ILI data set except that only the results without the A-Frame electrolytic contact data were significant at the 95-percent level in that case. Because two different contractors collected the data in these two sets, it suggests that data collection methods and/or interpretation were probably not consistent.

Additional 2 x 2 contingency table analyses were conducted to determine the strength of the associations between the PCM and PCM + ACVG indirect inspection and the LRGWUT results. Initial analyses considered both the total number of casings investigated by one or both LRGWUT systems that were used with respect to all indirect inspection results and without the A-Frame electrolytic contact results. The resulting Fisher's exact test p-values indicated no significant association between the methods. Considering both LRGWUT system results versus all indirect inspection results, the p-value is 0.167 suggesting that some association (~80-percent confidence) exists. Without the A-Frame electrolytic contact data included in the analysis the p-value is 1.00 indicating no association exists. Both of these comparisons were made based on LRGWUT data that indicated possible metal loss existed.

It was also noted the Teletest and GUL G-3 LRGWUT reported results differed in terms of the reported inspection result details. Teletest only provided metal loss results defined as "relevant" or "minor" indications with no "severe" or "moderate" indications reported. In addition to similar data relating to metal loss severity, the GUL G-3 results also included coating condition estimates and identified a possible short within one casing. This additional detail led to additional analysis only considering indirect inspection results reported in the GUL G-3 LRGWUT results.

Table 20 summarizes the comparison between information provided by indirect inspection and the GUL G-3 data that provided coating quality related data. The Fisher's exact test p-value is 1.00 which indicates that there is no association between the indirect inspection and LRGWUT results.

**Table 20. Operator A Analysis results – indirect and GUL G-3 coating condition results**

| | | LRGWUT G-3 | | |
|---|---|---|---|---|
| Indirect Inspection PCM + ACVG | | No Contact | Contact | Total |
| | No Contact | 0 | 1 | 1 |
| | Contact | 4 | 5 | 9 |
| | Total | 4 | 6 | 10 |

A second analysis of this same data was also done without including the A-Frame electrolytic short data similar to several that were previously discussed. For this case, Fisher's exact test p-value is 0.191 which indicates some degree of association between indirect inspection and the GUL G-3 results but not at the 95-percent level. It could be asserted that an association exists at about the 80-percent level but this is not a typically reported statistical result[6]. For the data in Table 21, it must also be stated that the apparent association is negative in the sense that No Contact in one method is associated with Contact in the other method. However, the difference between these analyses based on Tables 20 and 21 is meaningful in that the removal of A-Frame electrolytic contact data from the analysis again results in differences consistent with other analysis results where comparisons made using all indirect inspection results and without A-Frame electrolytic contact results.

**Table 21. Operator A Analysis results – indirect and GUL G-3 coating condition results (without indirect A-Frame electrolytic contact data)**

| | | LRGWUT G-3 | | |
|---|---|---|---|---|
| Indirect Inspection PCM + ACVG (without A-Frame Electrolytic Contact) | | No Contact | Contact | Total |
| | No Contact | 1 | 5 | 6 |
| | Contact | 3 | 1 | 4 |
| | Total | 4 | 6 | 10 |

[6] Confidence levels lower than 95-percent (i.e., 80-percent, or 90-percent) are often stated when considering ILI defect detection and sizing statistics.

It was also noted that at one casing location, the GUL G-3 results indicated a corrosion call while the Teletest results did not. Overall, however, the remainder of the results from the two LRGWUT systems was the same with respect to metal loss anomalies identified.

## Operator B

### *General ECDA Results*

Operator B's ECDA program covered 146 miles of pipeline including the trial LRGWUT results discussed in this section. The number of difficult-to-inspect locations consistent with Table 1 that were evaluated include:

- 449 cased road crossings
- 34 power line crossings (HVAC)
- 5 pipeline segments under paved roads
- 6 pipeline segments with parallel power lines (HVAC)

All indirect inspections were conducted with PCM and ACVG that identified a large number of coating fault indications resulting in 110 locations being selected for excavation and direct examination. About 80-percent of the excavations were in dry, arid soils with the remainder in moist or wet soils. At 20 of the 110 excavation locations, corrosion was found that was sufficiently severe to warrant action based on ASME B31G calculations.

Figure 3 summarizes results comparing the predicted indirect inspection outcome with the actual direct examination results. In Figure 3, the direct examination results are indicated on the x-axis and the indirect inspection results on the y-axis. While no road or cased crossings were dug, the other difficult-to-inspect areas were selectively sampled and included in this high-level measure of process and tool validation.

In Figure 3, the validity of Operator B's overall ECDA process is assessed in terms of the outcomes of all 110 direct examination excavations done for direct examination including difficult-to-inspect locations. This total response is the sum of results for the three severity categories for which errors or bias could develop – for one or all three severity categories – due to functionality or calibration of the DA-Tools and their ability to detect or judge the severity of indications. Because this total is the sum of three severity categories, errors or bias in one category could offset or bias the response in another category effectively masking the results invalid. Accordingly, it is also essential to evaluate these dig data in terms of the three individual severity categories, which were subdivided into the four dB-based (indirect inspection) severity metrics: very small, small, medium, and large.

Inspection of Figure 3 shows that the trend for the data labeled "total", shown there as the solid circles, follows a straight line for the number of dig sites where significant coating damage was expected based on the Indirect Inspection results, and the actual number of direct examinations where coating damage was detected. Not only is the trend a straight line, which is a necessary condition for a valid process, but this straight line also has a 1:1 slope, which indicates the process was correctly calibrated as it was implemented. The four dB-based severity metrics – very small, small, medium, and large – also are presented in Figure 3, with a unique symbol for each metric. Inspection of the figure at the level of these metrics indicates the results for severity metric category again fall on a straight line with a 1 to 1 slope. This again indicates the process and its severity ranking were valid as calibrated and implemented.

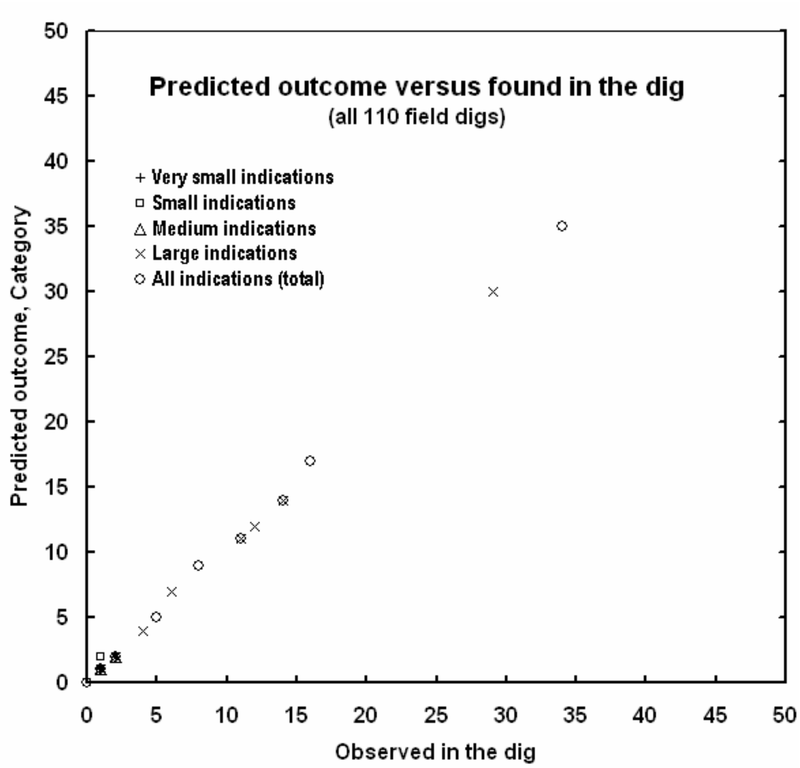


**Figure 3. Validation and success metrics for the ECDA process and tools**

Figure 3 also indicates that the ECDA process was valid, that the indirect inspection tools that were selected functioned effectively, and that defect severity was valid as ranked. Analysis of the underlying data shows that 107 out of 110 anomalies were classified by indirect inspection exactly as expected – equally, the DA process, tools, and ranking was accurate over 97 percent of the time, with very little scatter evident. Of the 80-percent of the excavations in dry soil areas, 3 indirect inspection severity classifications in the medium category were estimated to be more severe as compared to the direct examination results which resulted in a net 96 percent indirect inspection classification success rate.

The sizing of coating faults is likewise in general agreement with the indirect inspection predictions and the severity classifications, with large coating disbonded areas corresponding to the higher dB readings. This was determined to be an exponential relationship between these parameters that shows a high degree of correlation and further validates the ECDA process that was implemented by Operator B. This relationship is covered in the Discussion section of this report.

Excavations at one location in two different pipeline segments where no coating faults were predicted by indirect inspection were also conducted. At one location, no visually detectable evidence of coating damage was found. The other location showed a small site with coating mechanical damage but no apparent disbonding. Examination with a holiday detector[7] ("jeeping") indicated that a small fault, with no corrosion evident, did exist. This coating fault, with no visible bare metal below, was missed by the AC-based indirect inspection tools because the associated current drain was within background noise for the PCM tool. Coupled with the LRGWUT results discussed in the next section, the results validated the ECDA tools and processes implemented in this project.

***Operator B LRGWUT Results***

The objective of these trials was to determine the presence of coating damage as well as internal and external metal loss within the just-noted pipeline segments. In all cases the pipeline was interrogated in both the upstream and downstream directions from the test site. Interrogation in the downstream direction is referred to as the backward shot whereas that for the upstream direction is termed the forward shot. The longest segment interrogated was 30 meters while the shortest was 16 meters. The work was completed using commercially available LRGWUT non-destructive testing (NDT) technology, specifically that produced by Teletest using a pulse-echo system sensitive to coating discontinuities and metal loss – both external and internal.

Success in the use of such technology remains operator dependent. For this reason, the field crew implementing these trials comprised two operators both of whom held UT ASNT Level II certifications, had years of experience, and held degrees in Mechanical Engineering. That experience led to consideration of several important pipeline characteristics in developing the inspection analysis procedure. These included the coating type (epoxy), and the pipeline diameter and heavy nominal wall thickness (16-inch diameter with 0.550-inch wall). Another key factor included where the LRGWUT tool was to be placed, which followed visual inspection of the site by the inspectors. These characteristics and many other technical issues underlay various decisions made in analyzing and interpreting the data collected by the LRGWUT tool.

A trial application of LRGWUT methods was conducted at sites selected by Operator B that included pipeline crossings of a railroad and a small stream. This included a length of about 2 km of a 16 inch OD natural gas pipeline located in semi-dry, sandy soil. At the edges of the stream crossing, the local pipeline depth-of-cover was reported to be about 60 feet. The basic pipeline properties for this pipeline segment are shown in Table 22. Figures 4 and 5 illustrate the LRGWUT application locations.

**Table 22. Operator B Pipe characteristics at the LRGWUT trial-locations**

| | |
|---|---|
| Pipeline Diameter | 16-inch and 14-inch |
| Wall Thickness | 0.47-inch and 0.50-inch |
| Pipe Grade | X46 |
| Date of Installation | 1996 |
| MAOP | 1309 psig |
| Type of Coating | Coal Tar reinforced with Fiber Glass |

[7] Portable DC holiday detectors have a minimum output of approximately 9V, which is much higher than the potential differentials generated in the field for PCM.

| | |
|---|---|
| Coating Thickness | 0.2-inch to 0.28-inch |
| General Coating Condition | Partially disbonded in some locations |
| Type of Soil | Semi-dry, clay and sand |
| Burial Depth | 4.9 ft |
| Soil pH | 5.5 |
| CP System | Impressed Current |

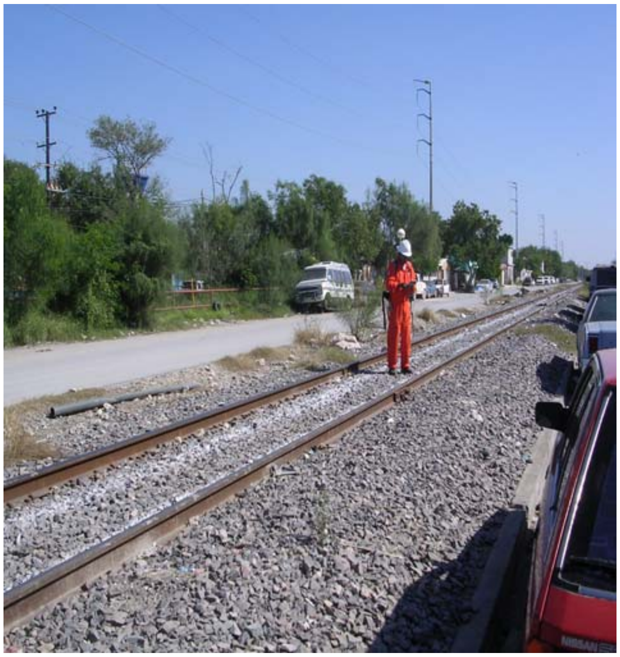

**Figure 4. Operator B rail crossing**

**Figure 5. Operator B stream crossing**

Two small ACVG indirect inspection responses were found within the rail crossing and no indications were found in the stream crossing. The indirect inspection results in this area and those nearby upstream and downstream are summarized in Figure 6. This visual tabulation illustrates signal level as well as the extent of the indications in the vicinity of this work.

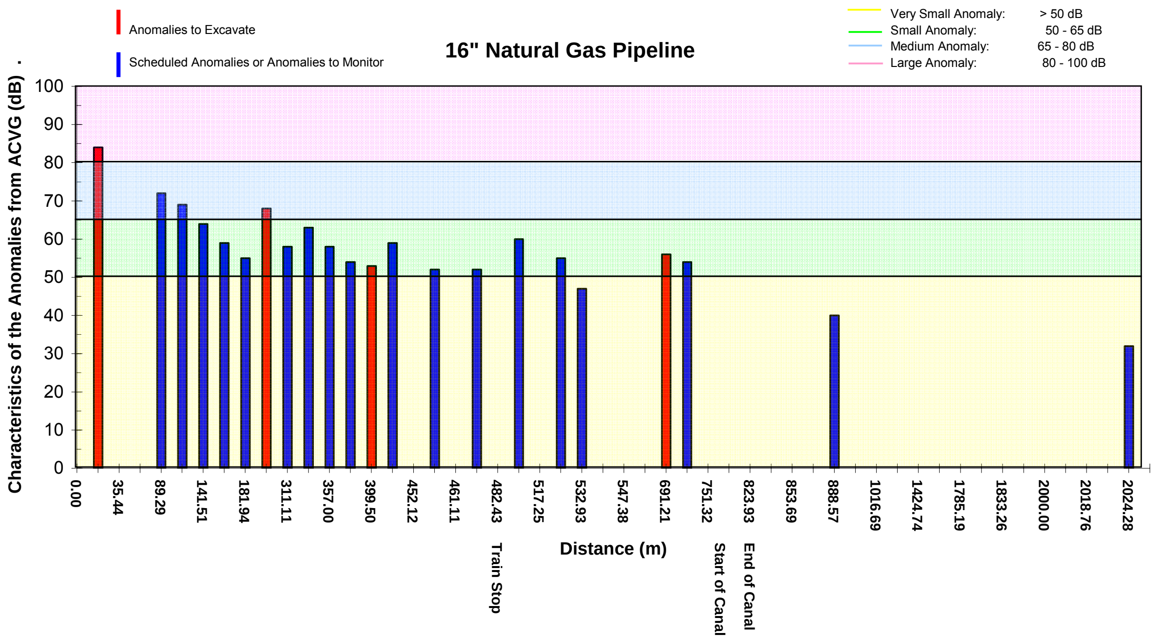


**Figure 6. Operator B ACVG Indications at and nearby the LRGWUT inspection sites**

LRGWUT direct examinations were conducted at the three locations as indicated in Table 23.

**Table 23. Operator B LRGWUT location and data summary**

| Site | Location | Direction | Indication | | Length, m | Comments |
|---|---|---|---|---|---|---|
| | | | Moderate | Severe | | |
| 1 | Stream-East Side | Backward | 0 | 0 | 30 | Indications of coating damage but no metal loss of consequence |
| | | Forward | 0 | 0 | 30 | |
| 2 | Rail crossing-West side | Backward | 0 | 0 | 25 | Indications of coating damage but no metal loss of consequence |
| | | Forward | 0 | 0 | 20 | |
| 3 | Stream – West Side | Backward | 0 | 0 | 16 | Indications of coating damage but no metal loss of consequence |

Comparison of the LRGWUT and the indirect inspection results showed that they were consistent. The ACVG indirect inspection indicated small anomalies (classified as "monitor") within the cased rail crossing and no indications under the stream crossing. The LRGWUT results did not indicate any moderate or severe indications at either location, however, coating damage indications were reported at all three excavation locations shown in Figure 6. These data indicated that LRGWUT and indirect inspection results appeared to provide consistent coating fault information and LRGWUT provides added value particularly where pipeline access is an issue. This implies locations that are difficult-to-inspect with above ground indirect inspection tools or where pipeline access for direct examination is an issue can be confidently inspected with LRGWUT techniques.

## Discussion

ECDA makes use of indirect inspection surveys to identify possible coating fault locations where external corrosion or other threats may be found and then infer their severity. Thereafter, the ECDA process assumes that a valid relationship exists between the existence and/or severity of the coating fault as characterized by the indirect inspection tool response and the existence and/or size of each fault found during direct examination.

Without such relationships there is no fundamental technical basis for predicting the severity of any of the indirect inspection indications. In turn this implies that all features identified during indirect inspection must be evaluated by direct examination. If all indirect inspection indications are excavated then there is no need for such relationships, however, the cost of such a practice would render ECDA impractical especially in cases where a large number of indications are found. Aside from obvious financial constraints, consideration of an excessive number of ECDA excavations and direct examinations even in easy access locations cannot be justified. Add to this the difficult-to-inspect locations such as in cased crossings and other areas identified in Table 1, such an empirical “dig-all” approach is clearly impractical. It follows that for a credible ECDA based pipeline integrity assessments:

- indirect inspection surveys must effectively identify possible coating fault locations that may include external corrosion or other threats associated with coating faults and then infer their severity, and that
- a viable, proven relationship must exist between the predicted occurrence of the **coating fault** and its severity as characterized by indirect inspection tools versus the fault found in direct examinations, and
- a viable, proven relationship must exist between the predicted occurrence and severity of the **corrosion threat** as characterized by the indirect inspections tools versus the detection and severity of the features found during direct examination.

Without such proven relationships there is no technical basis for ECDA, nor is there a sufficient foundation for ECDA based integrity assessments and reassessment interval calculations. Of these relationships, the last is most critical, as it relates to the existence and severity of the corrosion threat and the indication via the indirect examination. Without this relationship, there is no basis to conclude that the undug features considered other than an immediate concern are indeed small and innocuous from an integrity perspective.

The validation process central to the ECDA process is perhaps the easiest way to discriminate between a properly performed ECDA based integrity assessment and a simple field survey to potentially locate coating faults. Success in locating coating faults with the ECDA process begins with pre-assessment, wherein ECDA regions are identified, and two complementary indirect inspection macro and micro tools are chosen to ensure the defects are found. If the indirect inspection tools are not selected correctly, the ECDA process fails.

As previously stated, an inherent ECDA process assumption is that the presence of corrosion can be detected and sized by the indirect inspection tools and that the extent or size of the corrosion will vary with the size of the coating fault. On this basis, coating faults are first detected over longer intervals along the pipeline with a macro-tool, and then located more accurately with a micro-tool. The micro-tool focuses on a specific coating fault, or possibly small interacting faults, the signal strength – or amplitude – from the micro-tool is a measure of the size of that fault. Given that the size of a fault can range from very small (not visibly detectable) to the order of square feet, the signal strength characterizing the amount of current that leaks through the fault as detected by these AC-based tools is measured on a dB scale, whose logarithmic form is ideal to address this scenario.

Considering their pre-assessment results and indirect inspection tool capabilities, Operator B selected AC based tools including PCM as the macro-tool and ACVG as the micro-tool. Independently, Operator A also selected the same two tools for their ECDA program focused on cased crossings.

## Tool Selection is a Success Factor

One benefit that derives from Operator B's overall ECDA program was the opportunity for a quantitative comparison of results developed via AC-based technologies to earlier field-survey programs based on CIS and DCVG tools. Measures of the effectiveness of the AC-based tools in contrast to DC-based tools develops by comparing historical indications of coating faults found in prior over-the-line surveys using CIS, which was supplemented as needed by DCVG. For example, one line for which the coating condition was considered to be good had the order of hundreds of AC-based indications where prior DC-based surveys showed no problems. Digs confirmed both the indications and confirmed the anticipated correlation between severity and signal strength. In total, over 5000 indications were located under this scenario – all for arid, rocky, or hard-pan clay soils. Table 24 provides typical examples that provide a breakdown this total across several of the difficult-to-inspect segments considered for operator B. The worst case had many more than evident here, while the best case showed no disparity.

**Table 24. Comparison of indications for arid, rocky, and hard-pan clay**

| Identifier | AC-Based | DC-Based |
|---|---|---|
| 1 | 246 | ~ |
| 2 | 25 | ~ |
| 3 | 160 | ~ |
| 5 | 51 | ~ |
| 6 | 126 | ~ |
| 7 | 35 | ~ |
| 8 | 76 | ~ |

As the only difference involved in this comparison relates to AC-based versus DC-based tools, such results demonstrate the utility of the tools developed since NACE RP0502 was approved in 2002. It is clear in this context that the use of AC-based tools is favored for such soil conditions. Thus, the first of the above-noted ECDA process requirements – that Indirect Inspection surveys must effectively identify possible locations for the threat of concern and then infer their severity – was effectively demonstrated. This also demonstrated that a comprehensive pre-assessment step is an essential component for a successful ECDA program, as otherwise the nature of the soils could lead to a poor choice of ECDA regions and the tools appropriate for each region.

## Validation for Difficult-to-Inspect Areas – Operator B

Operator B's ECDA program also provided for a more detailed evaluation of the circumstances that underlie the higher-level test of the validity of the tools and the process shown earlier in Figure 3. Much narrower in scope as compared to Figure 3, this effort gathered data that allowed evaluation of the quantitative relationship between indirect inspection data and coating fault size, results which are shown in Figure 7. Experience correlating the output of AC-based tools as a function of actual coating-fault severity suggests the ACVG output from 0 to 100 dB can be subdivided into four categories that reflect the actual area of the coating defect. On this basis, Operator B considered values from 0 to 50 dB were categorized as very small, those from 50 to 65 db categorized as small, with those from 65 to 80 dB as medium, and those from 80 to 100 dB categorized as large.

Experience also relates these relative severity rankings to the nature and extent of the corrosion damage that has been empirically related to these categories. For amplitudes up through 65 dB, experience has shown that the associated corrosion typically is minor, whose sizes at typical growth rates are not problematic over the long-term. Such defects can be simply monitored over time, at return intervals the order of decades or more, which leads to the title "Monitored" for amplitudes up through 65 dB. In contrast, experience indicates the interval above 80 dB is associated with corrosion whose sizes at typical growth rates pose a near-term threat to the pipeline's integrity if it continues to operate at its current MOP and the corrosion remains active. Such defects can fail within months to a few years, which lead to amplitudes above 80 dB being termed "Immediate Action" indications. Finally, the group of amplitudes that are located between Monitor and Immediate reflect the range of corrosion scenarios bracketed between those just noted. This group from 65 to 80 dB cannot simply be monitored, nor do they require immediate attention, leading to their being termed "Scheduled Action" indications.

For success in ECDA, the relationships between indirect inspection predictions and actual coating-fault size must be repeatable at least for a given pipe diameter and set of soil and drainage conditions if the results of the Indirect Inspection are to be transformed reliably into metrics of corrosion severity. Likewise, the three windows in signal amplitude from 0 to ≤ 65 dB, from 65 to ≤80 dB, and from 80 to ≤ 100 dB must be consistently associated with the extent of coating-fault severity as determined in the Direct Examinations. The viability of these four definitions of severity and the three categories of indications is evaluated in Figure 7.

Figure 7 shows corresponding results for indirect inspections and direct examinations conducted by Operator B. This considers data for one pipeline diameter gathered under essentially similar soil conditions on a natural gas pipeline. In this case a total of 1796 indications were detected of which 35 were excavated and data gathered in support of the validation process. The actual coating-fault severity based on the measured defect area from the direct examinations on this pipeline is plotted on the y-axis versus the corresponding predicted severity based on the indirect inspection ACVG survey. It is apparent from Figure 7 that a relationship does exist between the severity of the coating fault as characterized by the output of the indirect inspections tool(s) and the defect severity measured in the direct examination. Experience indicates that the quality of the fit for the relationship shown in Figure 7 is very good – particularly in the transition region between lower levels of indicated severity to those above about 80 dB. The relationship in Figure 7 satisfies the second of the above requirements for a valid DA process. It remains to demonstrate the third.

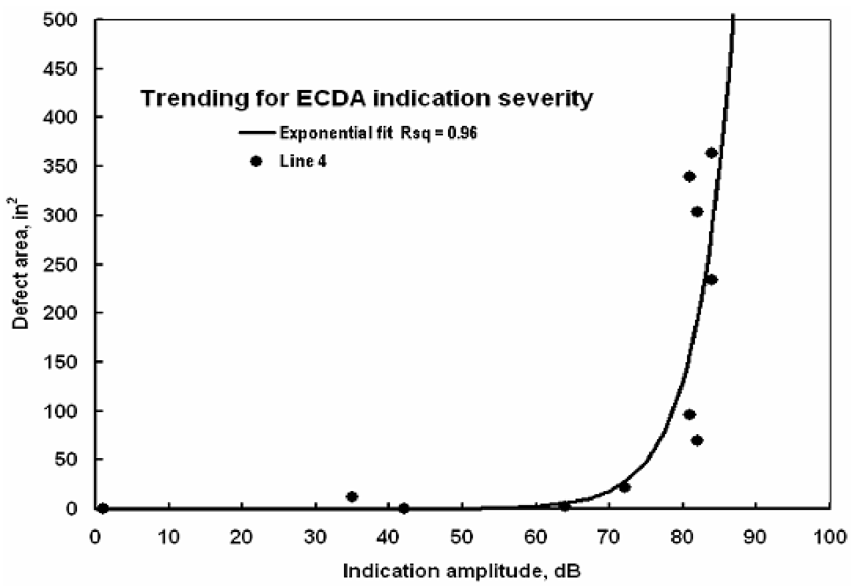


**Figure 7. Operator B Correlation between indirect inspections and direct examinations**

Figure 8 is identical to Figure 7, except that this figure also includes two dashed lines whose placement has been chosen to reflect mean trends evident in both the data and in the exponential fit to it. Note in reference to the dashed trend that lies close to the x-axis, defects with actual severity less than 75 dB whose severity was categorized as "scheduled action" do not appear characteristically different from those whose severity was categorized as "monitored". This observation means an ECDA practice that does not discriminate between the "very small" and "small" indication categories is practically viable. Indeed these results suggest there is little practical difference between signal amplitudes ≤75 dB, which in the case here suggests there is no need for more than two indication categories.

In contrast to the trends at signal amplitudes ≤75 dB, defects with actual severity just a little greater than 75 dB appear characteristically much different, which supports the use of the "immediate action" indication category beyond 80 dB, with the data there being reasonably represented by the almost vertical dashed trend line that lies close to the right-hand "y"-axis. Finally, there is a window of transition evident beginning at signal amplitudes of about 65 dB, which ends about 80 dB, with this area being termed "scheduled action" indications. Thus, the results in Figure 8 demonstrate that viable, proven relationships exist between the existence and/or severity of that threat as characterized by the output of the indirect inspection tools and the existence and/or size of each feature that is found during direct examination. It follows that the third of the above-noted requirements for the validity of the ECDA process and tools has been satisfied.

Results from Operator B's limited application of the Teletest LRGWUT system for direct examination of pipeline rail and stream crossings indicated that they were consistent. For this segment, the ACVG indirect inspection indicated small coating faults (classified as "monitor") within the cased rail crossing whereas there were no indications under the stream. The LRGWUT results did not indicate any moderate or severe metal loss indications at either location, however, coating damage indications were reported at all three excavation locations evident in Table 24. These data indicated that LRGWUT and indirect inspection results appeared to provide consistent coating fault information and LRGWUT provides value added particularly where pipeline access is an issue. This implies locations that are difficult-to-inspect with above ground indirect inspection tools or where pipeline access for direct examination is an issue can be confidently inspected with LRGWUT techniques.

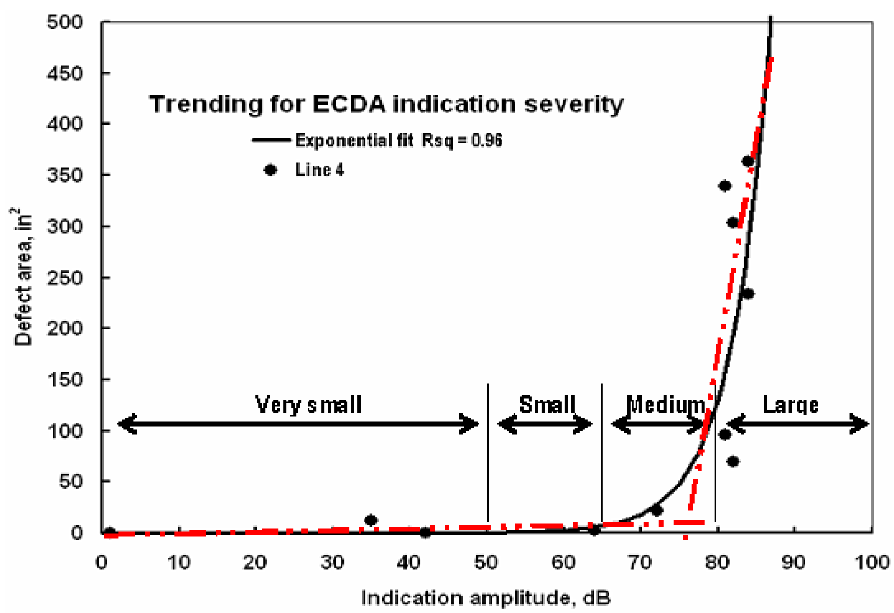


**Figure 8. Operator B Validation of Anomaly Severity Categories**

## <u>Literature Trends</u>

Reference 15 shows ECDA data that appear to exhibit the same trend shown in Figure 8. The predicted coating fault size using several indirect inspection tools have been plotted versus the actual size found during direct examination as shown in Figure 9 (Figure 56 in Reference 15) with the focus here on the ACVG data. A cluster of ACVG predicted coating fault sizes is located between about 55-60 while their actual sizes ranged from about 5 to 27. This exhibits the same general trend as evident in Figure 8 – beginning at an ACVG indication amplitude above about 75 dB. A dashed curve has been superimposed on Figure 9 depicting an approximate curve similar to Figure 8 to help illustrate the similarities between these figures in regard to the

ACVG data. Within the range of most of the data, Figure 9 suggests that DCVG provides a better coating fault size relationship between indirect inspection and direct examination than ACVG, which obviously is specific to the soil and pipe environment conditions encountered in the work reported, and possibly also to the ACVG and DCVG tools deployed.

## LRGWUT Statistical Analysis: Trends and Observations

Operator A's data consisted of two separate sets depending on the direct examination method used. One data set utilized previous ILI results and the other used LRGWUT. Analyses were conducted based on 2 x 2 contingency tables to determine the strength of the relationships between the indirect inspection and the two different direct examination methods represented. An evaluation method (i.e., Fisher's exact test) was used to estimate the association strength in all analyses. This is valid where for small sample sizes and minimum data cell count assumptions necessary for analyses based on the Chi-squared distribution do not exist.

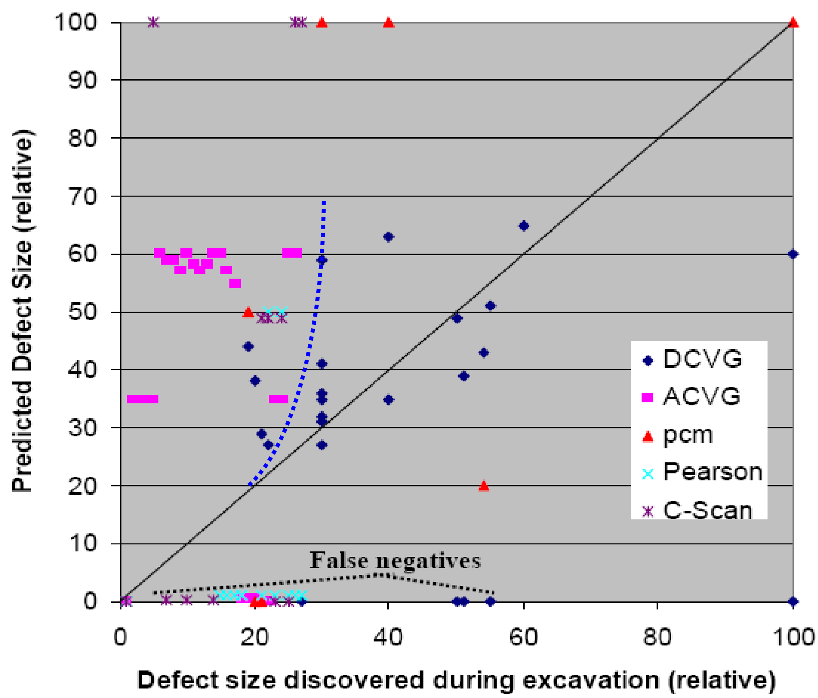


**Figure 9. Indirect Inspection versus Direct Examination Coating Fault Size(15)**

Indirect inspection results reported in Operator A's ECDA/ILI data set included suspected metallic and electrolytic contacts by PCM and similarly for the A-Frame ACVG results. Initial inspection of these data indicated that the number of reported A-Frame electrolytic contacts is disproportional with respect to the other indirect inspection suspected contact data. Also, the A-Frame electrolytic contact results did not agree with the C/S-P/S potential differences. Two contingency tables were constructed to evaluate this observation; one with all four indirect inspection results (Table 15) and P/S-C/S potential differences and the other without including the A-Frame electrolytic contact data (Table 16).

With all four indirect inspection results, the p-value was 0.113 and without the A-Frame electrolytic contact results the p-value was 0.002. Both of these suggest an association exists but the p-value without the A-Frame electrolytic contact indicates significance at the 95-percent level. The strength of the association between the two methods increases without the A-Frame electrolytic contact data as indicated by the lower p-value.

A similar analysis was conducted based on subset of Operator A's ECDA/LRGWUT data set for the elements including both indirect inspection results and P/S-C/S potential differences. Again, two contingency tables were constructed with and without the A-Frame electrolytic contact data as shown in Tables 18 and 19 respectively. The resulting p-value with the A-Frame electrolytic contact data was 0.037 and without it the p-value was 0.015. Both of these results are significant at the 95-percent level with highest association strength as indicated by the lowest p-value resulting from the analysis without the A-Frame electrolytic contact data. It should also be noted that when the A-Frame electrolytic contact data was removed the contingency table (Tables 18 and 19) did not change much as compared to Tables 15 and 16 where a much larger difference is evident.

The preceding results considering indirect inspection results and P/S-C/S potential differences provides evidence that A-Frame electrolytic contact data appears to be inconsistent as compared to the other three indirect inspection data elements. The initial data observations (Table 14) and both analyses provided evidence that this part of the A-Frame data appeared to be problematic and generated an excessive number of false positive calls. It should also be noted that Operator A personnel expressed some similar concerns regarding the number of A-Frame electrolytic contact calls during early discussions regarding these data.

These analysis results suggest that additional consideration of the indirect inspection procedures and an improved criterion that would result in a more accurate determination of the presence of an A-Frame electrolytic contact should be considered. Comparison of the contingency table modifications required when the A-Frame data was removed from both of the analyses discussed above also indicated a trend because two different contractors collected the results shown in the ECDA/ILI and ECDA/LRGWUT data sets. This suggested that some undefined difference existed between the contractor's methods; most likely during collection of the indirect inspection data.

Table 17 summarizes the results of five different contingency table p-values that consider the strength of the association between the ILI and several different combinations of indirect inspection results. In all cases the sample sizes are not the same because the difference between P/S-C/S potentials was not reported for all elements in the ECDA/ILI data set. Similar to the preceding analyses, the second and third rows of Table 17 also consider the association strength between ILI and all indirect inspection results plus the P/S-C/S potential difference and without the A-Frame electrolytic contact results. With all indirect inspection results included the p-value is 1.00 indicating no association and without the A-Frame electrolytic contact data the p-value is 0.250. From this latter p-value, it could be asserted that some association between ILI and indirect inspection results (without A-Frame electrolytic contact data) exists at a 75-percent confidence level. This result also supports the previous indirect inspection /P/S-C/S potential difference analyses by suggesting that the A-Frame electrolytic contact data, especially as reported in the ECDA/ILI data set, is problematic.

Consideration of a possible association between ILI and P/S-C/S potential difference shown in the first row of Table 17 resulted in a p-value of 0.125. This result indicated that some association does exist with a confidence level of about 85-percent. The remaining results in

Table 17 include the entire ECDA/ILI data set considering ILI and all indirect inspection results plus ILI and indirect inspection results without the A-Frame electrolytic contact data. With all indirect inspection results included, the resulting p-value is 0.290 indicating some association and with the A-Frame electrolytic contact data removed the p-value is 0.500, the association is weak.

Two additional contingency table analyses were done considering the coating condition and possible pipe/casing contact data reported only in the GUL G-3 LRGWUT data. The analyses considered the GUL G-3 coating condition data and indirect inspection results with and without the A-Frame electrolytic contact data. With all indirect inspection data included, the resulting p-value is 1.00 indicating no association exists while without the A-Frame electrolytic contact the p-value is 0.200 suggesting on association at the 80-percent confidence level. However, the association suggested by the 0.200 p-value is negative in that no contact in one method is associated with contact in the other.

The latter analyses were conducted using small data sets because the amount of LRGWUT information was limited. In order to better evaluate the association between LRGWUT and indirect inspection, additional data is needed. No attempt was made to compare the association between LRGWUT and P/S-C/S potential difference because only a few of the data elements included such information.

## Other LRGWUT Results

In addition to the sites investigated for Operator B, another Teletest LRGWUT inspection was conducted in late 2006 located in Oregon[16] for which ILI results serve as a reference for validation. The inspection focused on a 100 foot long cased road crossing in a 16 inch OD pipeline. Two shots were taken from excavations on the opposite sides of the road. The LRGWUT scan covered a total of 180 feet of pipe from the first excavation and 165 feet from the other. Comparisons between the distances between girth welds was determined from the LRGWUT and ILI and summarized in Table 25 which indicate that a good correspondence was achieved.

**Table 25. Comparison of ILI and LRGWUT Distances Between Girth Welds[16]**

| Welds | ILI (ft) | Teletest (ft) | Difference (ft) | % |
|---|---|---|---|---|
| W1-W2 | 48.51 | 48.31 | 0.2 | 0.41 |
| W2-W3 | 48.55 | 48.92 | 0.37 | 0.76 |
| W3-W4 | 48.89 | 49.74 | 0.85 | 1.71 |
| W4-W5 | 48.71 | 49.69 | 0.98 | 1.97 |

Data collected from the LRGWUT scans was compared with the ILI data in a graphic format as shown in Figure 10. The LRGWUT results are at the top of Figure 10 with arrows extending to the corresponding feature in the ILI results graphic below.

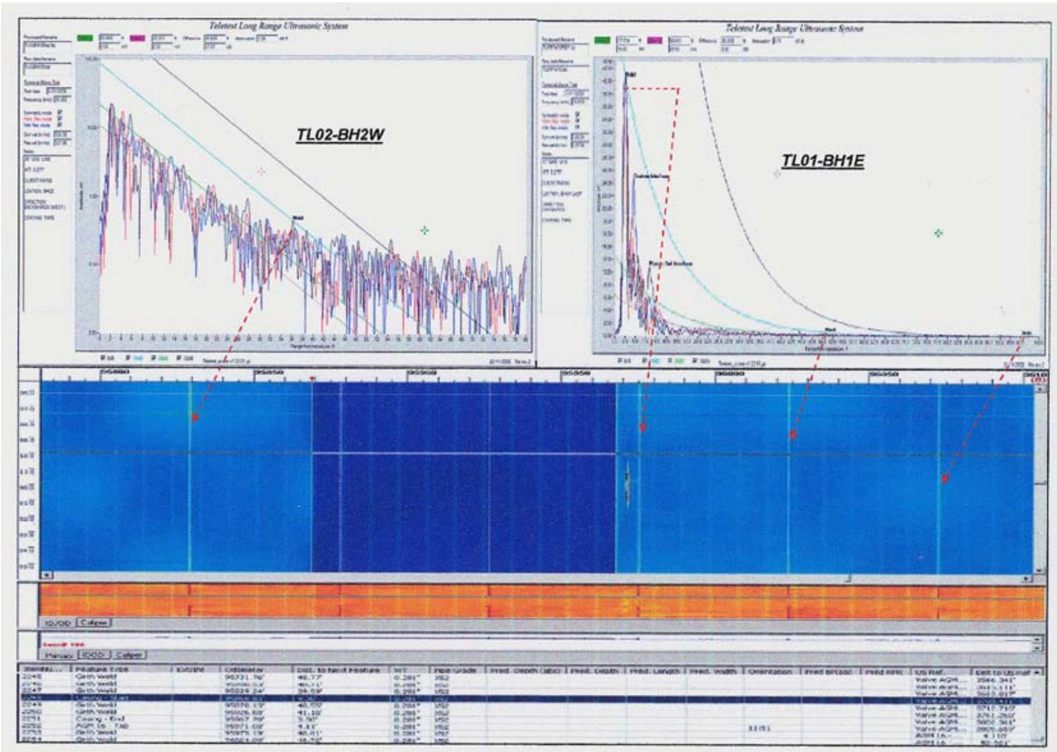


**Figure 10. Illustration of LRGWUT comparison to ILI data[16]**

An additional reference to LRGWUT applications and results on pipelines[17] was also considered. In one case cited, LRGWUT was applied to a 2000 foot segment of 20 inch OD pipe. This segment was then removed for visual examination. It was found that the pipe was in poor condition which adversely affected data interpretation. Only the most severe anomalies were identified during data analyses of about 650 feet of pipe. A total of 85 anomalies were identified by visual examination. Of this total:

- 6 anomalies were below the detection threshold,
- 7 detectable anomalies were missed by the equipment (false negative result),
- 72 anomalies were detected by the LRGWUT system (true positive result),
- 48 anomalies were identified by the technician, and
- 5 anomalies were incorrectly called by the technician

Overall, the LRGWUT system detected 91-percent of the anomalies above the detection threshold but the technician only identified 66-percent, which represents the "real" end result. This information is consistent with the results from the ECDA results reported herein – both Operators considered LRGWUT technician competency and training to be an essential element in the successful completion of such work.

A brief reference to some results from a larger Northeast Gas Association study of LRGWUT applications to pipe within casings was also cited in Reference 13. In three LRGWUT locations, no metal loss anomalies were detected by the equipment and none were found during verification. From this work, it was concluded that the LRGWUT system detection capabilities are good but signal interpretation skills needed improvement. Again technician skill and competency were considered to be essential to LRGWUT success.

The ECDA projects conducted by Operators A and B have re-validated what was known beforehand—proper completion of a comprehensive pre-assessment step is an extremely essential element in any ECDA application. For ECDA applications including difficult-to-inspect areas, it is even more so. One of the most difficult of those areas listed in Table 1 is cased crossings. The pre-assessment criteria listed in NACE RP 0502 were meant for more general ECDA applications. Where ECDA will be conducted in areas containing cased crossings, more specific pre-assessment criteria would be useful to aid in proper tool selection and possibly for prediction of the extent of coating defects and any corrosion. Because cased crossings affect both the indirect inspection and direct examination steps more specific data would also be useful to guide direct examination procedures**.** For casing specific ECDA applications the data elements that should be considered for inclusion in the pre-assessment step are provided below:

- Vented vs. non-vented
- Existence of test stations plus historical data
- Spacers (metal, non-metal)
- End seals (and condition, if known)
- Filled or not (and material if filled)
- Casing pipe type (corrugated/galvanized/plain/other)
- Adjacent soils (classification and chemical composition)
- Depth of cover at casing ends
- Casing Access
- Casing length
- Details of appurtenances within 100 feet of both casing ends
- Locations of above/below ground structures within500 feet of casing ends
- Prior ILI data through casing
- Historical operational data concerning the casing being evaluated an other similar casings in the same pipeline or adjacent pipelines in the same area
- Repair/maintenance data
- Pipe coating and condition (adjacent pipe and within casing)
- Relevant pipe inspection reports
- Local area cathodic protection history (periods with no or ineffective CP)
- Local above ground conditions (asphalt/concrete pavement/access issues/etc.)
- Topography
- Installation date
- Potential for introduction of high voltage current on to the pipeline (lightning/HVAC)
- Comparison of local pipe-to-soil (P/S) and casing-to-soil (C/S) potentials at the casing ends

Multiple casings could be considered as a unique ECDA region provided that the pre-assessment results indicated that the same indirect inspection techniques would apply and sufficient similarity between the locations could be established.  Otherwise, multiple regions would be necessary.  The last item in the above list was added because Operator A's results indicated that such data is useful for determining if casing shorts exist which can be used to infer coating/pipe condition within the casing.

Such data can also be used in a prioritization process that would be beneficial (especially for pipelines with a multitude of cased crossings) for scheduling ECDA activities and as metrics for identifying higher risk cased pipeline segments for initial indirect and direct assessment activities.

Direct access to the external pipe surface within the casing is limited.  Verification of the indirect inspection step could then be based on:

- Prior ILI results through the casing being evaluated
- Results of LRGWUT evaluations
- Tethered (wireline) ILI results of pipeline within the casing
- Visual examination of the pipe surface near the casing ends
- Removal of several feet of casing at one or both ends for pipe examination.
- Pressure testing at ~5 psi to evaluate end seal condition.
- Complete removal of pipe from the casing and direct visual examination

# Summary and Conclusions

The present project was initiated to support the further development of the ECDA process through evaluation of technologies that have evolved since 2002, in part to fill the gaps that existed then. It also considered issues that may indicate the need for changes in RP0502 that will be considered in the near future by NACE TG 041. Though field application of tools has evolved since the 2002 approval of RP0502, this project extends the knowledge base when dealing with ECDA regions currently considered difficult to inspect. The experience gained will facilitate broader effective used of the ECDA process moving toward its utility throughout the range of circumstances that might be encountered along typical pipeline routes.

This project developed an independent assessment and/or verification of ECDA over a range of difficult-to-inspect areas, which lead to suggestions and/or insights to make the ECDA process broadly feasible in such areas so operators have more complete and effective ability to manage the integrity of their complete system.

The objective was to assess the viability of tools that have evolved since the consensus of "difficult to inspect" areas was formulated for RP0502 as approved in 2003. This project targeted pipeline within cased crossings, or traversing arid, rocky, or hard-pan clay, or situated under pavement or concrete in scenarios. Consideration also was given to cases where multiple lines lay in one RoW, and high voltage alternating current fields exist over or adjacent to the RoW. The outcome was sought as an assessment whether ECDA can be feasible and effective in such areas. Where the evidence was clear-cut, the answer came in yes-no format, whereas suggestions or modifications were developed for the remaining applications. The results reflect evaluation of ~165 km of difficult-to-inspect segments, including evaluation of more than 60 crossings through work for two major pipeline operators, denoted Operator A and Operator B.

Operator A's ECDA project focused on integrity assessment of pipe within cased crossings which is the highest ranked difficult-to-inspect area shown in Table 3. A specific ECDA procedure was developed by Operator A to address the casing issue including AC based indirect inspection tools and LRGWUT methods for direct examination of pipeline segments within cased crossings. Operator B conducted a more wide ranging ECDA program that included 146 miles of pipeline segments throughout their operating area. Operator B also made use of AC based indirect inspection tools and a limited LRGWUT trial application. Their ECDA program included cased crossings and several of the other difficult-to-inspect areas listed in Table 3.

## Operator A

The following conclusions pertain to Operator A's casing ECDA program:

- Statistical analyses of both of Operator A's casing ECDA data sets were done using 2 x 2 contingency tables to determine the strength of the association between indirect inspection suspected contacts and the difference between P/S and C/S potentials. Comparisons were made using all indirect inspection results[8] and without including A-

[8] Indirect inspection results included both PCM and A-Frame suspected metallic and electrolytic contacts.

Frame electrolytic contact data. The association strength was highest (~95-percent confidence) for the data without the A-Frame electrolytic contact.

- In addition to the preceding conclusion, several other contingency table analyses all indicated that the indirect inspection A-Frame electrolytic results were problematic and provided no added value. These results also suggested that the A-Frame procedure and data interpretation criteria with respect to A-Frame electrolytic contact estimates should be re-evaluated. Statistical analyses also suggested that the contractor conducting the indirect inspections represented in the ECDA/LRGWUT data set provided better results as compared to the ECDA/ILI data set as indicated by higher confidence levels.
- Several contingency table analyses were conducted to evaluate the association strength between ILI results versus indirect inspection and P/S-C/S potential differences. Where ILI and P/S-C/S potential differences were considered, it could be asserted that the confidence level indicating the strength of the association was about 85-percent. Considering ILI versus indirect inspection results both with and without A-Frame electrolytic contact data, the association strength was minimal. However, indirect inspection responds to coating faults and ILI detection of metal loss anomalies. Only 4 ILI calls were included in the ILI/ECDA data set so a statistically significant strength of association should not be expected for this data.
- Contingency table analyses were conducted to evaluate the strength of the association between LRGWUT results versus all indirect inspection results and without A-Frame electrolytic contact data. This included the total number of casings inspected by one or both LRGWUT systems based on LRGWUT corrosion calls. The resulting p-values indicated no association in both cases. Two additional similar analyses were conducted using only the GUL G-3 LRGWUT coating fault information that was included in their reports. Without the A-Frame electrolytic contact data, the p-value suggested some association exists, however, it was negative. That is, no contact with one method was associated with contact with the other. The analysis with all indirect inspection data indicated no association exists.
- Information contained in the literature(16,17) emphasized the need for competent, experienced LRGWUT equipment operators and analysts plus improved anomaly data libraries to assist with analyses. It was suggested that the inherent LRGWUT equipment capabilities was better than the current level of interpretation capabilities. One indication of this was a metal loss call by the GUL G-3 system and no call by the Teletest LRGWUT system on the same casing. It is possible that such a situation coupled with the small amount of LRGWUT data adversely impacted the results of the statistical analyses conducted herein. Additional LRGWUT data would be beneficial and should include both metal loss and coating condition anomalies to facilitate analyses.
- From their observations of the performance of two LRGWUT systems and data interpretation, Operator A’s pipeline integrity staff were convinced that competent, experienced field technicians and data interpreters were a key element in achieving a successful result. This was consistent with LRGWUT results reported by others(16,17).

## Operator B

Important general conclusions from Operator B’s ECDA process include:

- Data developed and analyzed in the direct examination step validated the ECDA process and the AC based indirect inspection tools as implemented and interpreted for Operator B. Process-success metrics indicated that the AC-based tools and the related data analysis processes correctly identified the presence and severity of coating faults that could have contained external corrosion or other threats 96 percent of the time. This included pipeline segments with parallel pipelines, adjacent HVAC electric transmission, and cased road/rail crossings listed in Table 3.
- Historically favored DC-based indirect inspection tools used in prior over-the-line field surveys and for ECDA indirect inspections in accordance with NACE RP0502 tended to be ineffective in Operator B's operating area where arid, clay, or rocky soils exist. AC-based indirect inspection tools (i.e., PCM, ACVG) proved to be much more appropriate. This was demonstrated by comparison of the much larger number of coating fault locations detected by the AC methods and confirmed by direct examination as compared to prior DC based surveys.
- As demonstrated by comparison to direct examination results and data analyses, AC-based surveys consistently predicted locations of coating faults during the ECDA process. Many of the coating faults involved major disbonds covering areas that in some cases were on the order of square feet. In a few instances, very small coating faults found by a holiday detector were missed by the AC based indirect inspection tools.
- Where external corrosion was identified in association with coating faults, trending identified causative factors along with technical drivers as the basis to manage this corrosion as part of the ECDA post assessment step.
- The results of the limited LRGWUT application for conducting direct assessments of cased crossings suggested that this method provides added value with respect to difficult-to-inspect areas. The discussed methodology can provide sufficient information to identify and prioritize corrosion defects to ensure the integrity of these areas. Although the LRGWUT results obtained from this ECDA project were encouraging, Operator B's position was that further validation is necessary to more definitively assess the capability and reliability of LRGWUT for direct examination of difficult-to-inspect areas. Wider application of LRGWUT technology can then permit ECDA to be performed in areas where the process was not previously feasible.
- The qualifications and experience of the management, contractor, and field personnel / contractor / management are absolutely critical with respect to the success or failure of the ECDA process. Applications in difficult-to-inspect areas require a high level of expertise in proper indirect inspection tool operation and data interpretation.
- Data alignment is critical – particularly where sub-meter sensitivity GPS equipment is used.
- Additional conclusions from Operator B's ECDA program included aspects related to indirect inspection and direct examination, as follows:

  <u>Indirect Inspection</u>

  - AC based indirect inspection tools performed effectively and consistently in arid, rocky soils containing salts or soils with salt caps. This was verified by the large number of anomalies prioritized as "immediate" when compared to prior DC based indirect inspection results.

*Consideration should be given to revising NACE RP0502 to reflect this experience to the extent it gains consensus.*

- AC-based indirect inspection tools can be used on bonded parallel lines (~6 or less) located in high-tension fields – but this requires much more skill and experience, with data alignment during interpretation essential to success along with appropriate data processing.

  *Consideration should be given to revising NACE RP0502 to reflect this observation to the extent it gains consensus.*

- AC-based tools proved to be effective in the difficult-to inspect areas including those under pavement and under concrete. AC based indirect inspection tools performed effectively and consistently through all surface layers encountered without drilling or cutting to provide access as required for DC based tools.

  *Consideration should be given to revising NACE RP0502 to reflect this experience to the extent it gains consensus.*

- Difficult-to-inspect areas were found during the ECDA process that had not been identified or documented during pre-assessment or in discussions with Operator B's field personnel. This included parallel lines that existed that were not known for certain in advance, line location problems, bond locations, and problematic rectifiers. ECDA in such locations were successfully completed in large part by AC-based tools. This is a clear advantage in assessing poorly maintained segments.
- This work confirmed that HVAC electric transmission lines parallel to the pipeline RoW can adversely affect PCM "macro" interval indirect inspections. This effect was largely eliminated by more extensive use of "micro" interval ACVG indirect inspections.
- The trends in Figures 7 and 8 imply the PCM and ACVG tools saturate once the integrated effects of the coating defect reached a given size.

  *Consideration should be given to this possibility by the tool developers and suppliers, as it could limit their utility or necessitate re-inspection or require further digs due to problems encountered in validation.*

<u>Direct Examination</u>

- The results of the direct examination indicated that the indirect inspections were discriminatory in locating sections of the pipe which are of interest from a pipeline integrity point-of-view even in difficult-to-inspect areas. No discrimination was noted in predicting areas of corrosion or coating damage without corrosion (the immediate indications were no more likely than the scheduled indications to include corrosion defects).
- Operator B included a limited evaluation of long-range guided-wave ultrasonic technology (LRGWUT) as a direct-inspection technology, in contrast to its more usual role as an indirect-inspection tool. This work represents Operator B's first step toward developing a database needed for a wider application of this method for direct examination. If proven in this role, LRGWUT would avoid the cost and other complications associated with excavating difficult-to-inspect areas such as

pipelines in cased crossings, under concrete, or in river crossings. Comparison of the LRGWUT and the indirect inspection results showed that they were consistent. The ACVG indirect inspection indicated small anomalies (classified as "monitor") within the cased rail crossing and no indications under the stream. The LRGWUT results did not indicate any moderate or severe indications at either location, however, coating damage indications were reported at all three excavation locations.

> *Consideration should be given to further evaluation of LRGWUT as a surrogate for direct examination as it would bring great process efficiency with a corresponding cost impact.*

# Recommendations

The field work and related data interpretation gave rise to a number of observations that bear further consideration as follows:

- Indirect inspection in arid soils, rocky areas, and hard-pan clays, including salty soils or soils with salt caps was effectively accomplished via AC-based technologies. This observation should be considered in the next revision cycle for NACE RP0502 to the extent it gains consensus.
- Indirect inspection was effective on bonded parallel lines (~6 or less), including lines located in high-tension fields via AC-based tools. While clearly this required much more skill and experience, and effort in data alignment and interpretation consideration should be given to revising NACE RP0502 to reflect this observation to the extent it gains consensus.
- Indirect inspection for pipelines under pavement and under concrete also was effective through these surface layers via AC-based tools, without drilling or cutting to provide access. Redefinition of difficult-to-inspect should reflect this observation in revising NACE RP0502 to the extent it gains consensus.
- While HVAC electric transmission lines parallel to the pipeline RoW can adversely affect PCM “macro” interval indirect inspections, this concern was largely eliminated by more extensive use of “micro” interval ACVG indirect inspections. This observation should be considered in the next update to NACE RP0502, to the extent there is consensus to support it.
- The signals appeared to saturate for both the PCM and the ACVG tools once the sensed effect of the coating defect reached a given areal size. As this can confound the utility of these tools and require re-inspection or further digs due to problems encountered in validation, consideration should be given to redesign and retrofit by the tool developers and suppliers.
- Consideration should be given to further evaluation of LRGWUT as a surrogate for direct examination as it would bring great process efficiency with a corresponding cost impact.

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# Appendix A: PCM and PCM + ACVG

This Appendix describes the operation and capabilities of the Pipeline Current Mapper (PCM) and the "A-Frame" attachment that can be used in conjunction with the PCM to conduct alternating current voltage gradient measurements (ACVG). Both PCM and A-Frame are trade names for devices produced by Radiodetection Inc. PCM is also classified as a current attenuation technique. These indirect inspection tools were used by both Operator A and B.

In terms of ECDA indirect inspection techniques, PCM is a "macro" tool because current attenuation measurements are made at longer increments typically between 50 and 150 feet. The A-Frame AVCG attachment is a "micro" tool because voltage gradient measurements are made at ~3 foot intervals.

## PCM

The PCM is an electromagnetic technique that does not require soil contact to conduct measurements. It is useful to conduct pipeline surveys where arid soil conditions exist and over paved areas because contact resistance does not influence the measurements. A signal generator is used to impress a low frequency (4 Hz) on the pipeline current attenuation measurements and other frequencies (98 or 512 Hz) are used to locate the pipeline and also provide depth of cover measurements. The latter measurements are also useful for input to pipeline integrity assessment data bases.

A PCM receiver essentially consists of a magnetometer attached to a high accuracy pipe locator thus resulting in an instrument capable of measuring the magnitude and direction of current flow along a buried pipeline. It also contains the necessary electronics and software to make the required calculations and display the results and is compatible with GPS equipment

The principle of the PCM is that the frequency is so low, the effects of induced and capacitance coupling to other pipelines is effectively minimized and the natural signal decay due to these effects is also minimized. All current attenuation that is measured is then attributed to resistive losses such as coating defects or contacts to other structures. Flowing current attenuates as a function of distance along the pipeline through the steel pipe resistance and faults in the coating. Increased attenuation is found at locations where coating degradation is present or contact with foreign objects exists

In a PCM plot, the current attenuation can be both positive and negative so the only interpretation available to indicate anomaly severity is the rate of current attenuation (e.g., dbmA) change per unit length. Current attenuation as a function of distance is obtained. The PCM output can indicate current attenuation in terms of mA or dbmA versus distance with dbmA preferred to provide a better comparison of fault magnitudes over the distance being evaluated. Figure A-1 illustrates a typical PCM current attenuation plot in terms of dBmA versus distance.

Without any external influences, the current attenuation would be represented by the areas in Figure A1 that show an essentially straight line with a minimal slope. However, where abrupt slope changes occur as illustrated in Figure A1, some feature has caused the decay rate to locally increase. This could be a result of a coating fault or other sources such as but not limited to the following:

- Field distortion due to tees, bends, and abrupt pipeline depth changes.
- HVAC electric transmission lines
- Metallic structures near the pipeline being evaluated

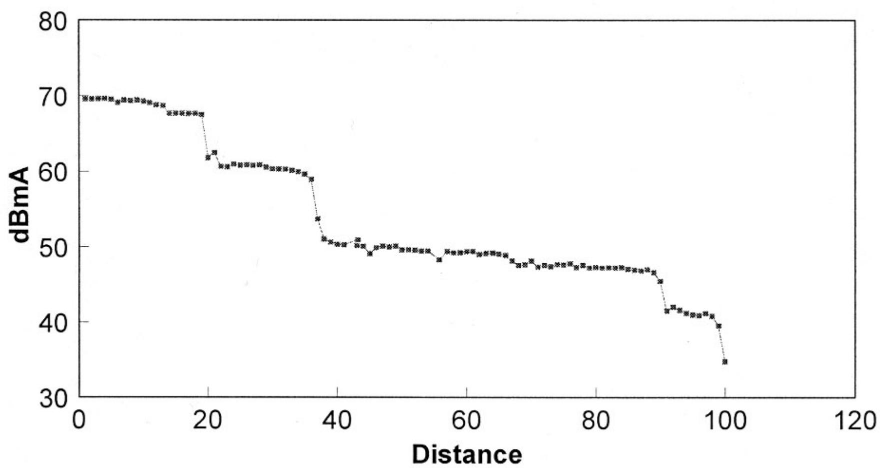


**Figure A1.  Typical PCM Plot as dBmA versus Distance**

For the PCM applications considered in this report, the last two potential error sources listed above are particularly relevant.  Operator A applied PCM to cased pipe which is a metallic structure surrounding the section of pipeline being evaluated.  Operator B encountered pipeline ROW that was parallel to high voltage electric transmission lines and other adjacent pipelines which necessitated corrective measures.

## PCM + ACVG

The A-Frame attachment to the PCM receiver enables measurement of local voltage gradients along a pipeline.  This option requires ground contact through spikes at the base of the A-Frame to be pushed into the ground.  It can also be used over hard surfaces such as concrete or asphalt by wetting the spike contact area or the use of wet sponges at the contact points.

The A-Frame is first aligned parallel to the pipeline and readings made with an arrow in the output display pointing towards the likely fault.  As the fault location is passed, the indicating arrow reverses direction indicating the fault location was passed by.  The fault severity and epicenter is then assessed by making readings with the A-Frame oriented perpendicular to the pipeline.

# Appendix B: Operator A AC-Tool Procedures

A major element of Operator A's casing ECDA procedure utilized indirect inspection tools including PCM and PCM + ACVG to detect either metallic or electrolytic shorts between the pipeline and casing. Metallic shorts imply a hard contact between the pipe and casing and electrolytic shorts indicate water and/or foreign This Appendix describes the required connections, survey procedure, and interpretation of the results when using the PCM alone and then with the A-Frame option.

## PCM Only

### *Connection*

PCM equipment should be connected to the rectifier nearest the casing to be inspected. The rectifier should be off and isolated from the pipeline when the connection is made. If no rectifier is available, the equipment should be connected to a test station that is at least 200 feet from the casing end. Structures parallel to the casing being inspected (i.e., pipelines, fences, drain culverts etc.) should not be used for ground points. Transmitter frequency selector is set to "ELF" with current direction.

### *Conducting Survey*

First determine the magnitude current flow in both directions at the connection point. Where a majority of the current is flowing from the direction of the casing, a shorted casing may be indicated. If such current flow is minimal, this may indicate that no casing short exists.

Obtain at least three PCM measurements (4 Hz current, direction, and depth) on the upstream casing end at 50 foot intervals. The first reading should be taken at the upstream casing end and then at 50 intervals away from the end. Record the receiver db level at each measurement location. This sequence is then repeated at the downstream casing end. All PCM measurement locations should be located with a sub-meter accuracy GPS unit and all readings documented for analyses and interpretation.

### *Survey Results and Interpretation*

Non-shorted Casing

- Minimal (typical local current loss or less) or no loss across casing.
- Small locate signal loss across casing.
- Locate signal loss across casing but signal returns to nearly the same level as the opposite end of the casing.

Electrolytic Short Indication

- Higher level of current loss across casing (as compared non-shorted condition).
- Locate signal loss across casing but signal does not return to nearly the same level as the opposite end of the casing.

Metallic Shorts (metal-to-metal contact)

- Current loss across casing with minimal current or signal level at the opposite end. Where the signal loss is large (10 db+) and the current loss is 25-percent or greater, a metallic short is indicated. In cases where the signal loss is 10 db or less and the current loss is less than 25-percent, a resistance contact is most likely.
- Current and signal loss at either end of the casing indicates a metallic short exists at that end of the casing.
- Metallic contact not located at the casing ends can be indicated by signal and current loss at the point of contact within the casing.

## **PCM + ACVG**

### ***PCM Connection and Survey***

The PCM transmitter is connected between the pipeline and casing potential test wire (or vent). The frequency selector is set to "ELF" with current direction. Conduct a survey over the casing concentrating on areas near the ends. Two to three PCM measurements (4 Hz current, direction, and depth) should be made at both casing ends. At the end where the PCM transmitter is connected, conduct measurements at 50 foot increments away from the end over the pipeline. At the opposite end, obtain at least one PCM measurement over the casing (or near the casing end) and two more measurements at 50 foot increments way from the end and over the pipeline. Metallic contacts are indicated by a signal and current loss at the point of contact. Resistance contacts are indicated by lower levels of signal and current loss.

An A-Frame survey is conducted over the casing (green leg away from transmitter and red leg towards) with probes parallel and over the pipeline. The receiver screen will display the db reading and directional indication arrow. All locations should be recorded using a sub-meter accuracy GPS unit.

The A-Frame is best suited for use in earth environments but it may be necessary to wet the area around the probes to assure good soil contact. When used on concrete surfaces, the area around the probes should be sprayed with water or wet sponges used to facilitate contact. However, wet sponge use on asphalt surfaces may lead to questionable results.

The direction of a fault or contact is indicated by the display arrow. When the point of contact is passed, the arrow will direct will reverse. Displayed db levels will increase as the fault or contact location is approached and decrease as it is passed. At such a location, the A-Frame is then rotated the perpendicular position on one side of the pipeline and then the other. The arrow indications in these positions should point toward the pipeline and contact point. The point of contact is a null point with no arrow indication with the lowest db level.

### ***A-Frame Survey Result and Interpretation***

The largest db level found when the fault or contact point is approached or when the probes are in the perpendicular position should be recorded. Maximum values less than 80 db can be considered as resistance contacts and 80 db or higher indicate a metallic contact location.

# Appendix C: LRGWUT for ECDA "Direct Examination"

## Background

In most applications, long-range guided-wave ultrasonic technology (LRGWUT) is considered an indirect inspection technology, as this tool is much like the AC-based or DC-based survey tools used in supporting ECDA indirect inspection. According to the ECDA process detailed in RP 0502, the indirect inspection step is followed by direct examinations to establish the accuracy of indirect inspection step and use of the related survey data as input to the post-assessment step – including validation of the DA-Process, reprioritization or processing of all indications that have not been directly evaluated, and analysis of the re-inspection intervals for all indications.

For such cases, LRGWUT might be used to evaluate difficult-to-inspect areas, such as pipelines in a cased crossing, or pipelines under concrete, or pipelines in a buried river crossing. In all such cases, LWGWUT serves as a surrogate for other indirect inspection survey tools that fail to function adequately at such sites – which lead to one definition of "difficult to inspect" in the terminology of NACE RP0502. This terminology was inserted into the RP as it was drafted in 2001, and has remained since. In this application the terminology "difficult to inspect" reflects the fact that the DC-based indirect inspection tools available as the RP was drafted were ineffective in such scenarios.

With the advent of field-proven AC-based tools alternative technologies that function for pipelines in a cased crossing, under concrete, or in a buried river crossing, the terminology in RP0502 should change, with subsequent revisions of this RP reflecting the viability of AC-based tools for use. Then, as now, there remains the problem of validating the results from the indirect inspection. This validation poses is a problem because no operator wants to excavate and expose pipelines in a cased crossing, under concrete or paved surfaces, or in buried river crossings simply to demonstrate that ECDA has worked and that post-assessment is valid. LRGWUT is one potential approach to such validation – at least for many such cases. As these tools are evolving and being proven through excavations made in difficult to inspect areas, it will be possible to accept the results of such technologies when implemented by qualified, field-proven DA service providers.

Operator A has examined a large number of cased pipeline locations with LRGWUT as the means of direct examination of part of this cased pipe population. One objective of this work was to develop improved confidence in their casing ECDA procedure and application of LRGWUT as reliable method of conducting direct examination of such locations. Clearly, use of LRGWUT remains remote to the defects potentially developing at the indications identified by the above ground, AC-based indirect inspection tools (i.e,. PCM and PCM + ACVG) applied by Operator A. Its ultimate viability as a direct-examination tool follows only as its use is proven for such cases.

The objective of the LRGWUT direct examination conducted by Operator A was to determine the presence of metal loss defects and possibly other anomalies in pipe segments within casings. Although LRGWUT service providers offer to provide information pertaining to coating loss and disbonded coating locations, identification such anomalies is currently based on inferential techniques and Operator A indicated a limited interest in such information.

## Approach and Principles of Operation

The LRGWUT work conducted by Operator A was completed using commercially available non-destructive testing (NDT) technology, specifically that produced by Plant Integrity Ltd. (Teletest) and Guided Ultrasonics Ltd.(GUL or G-3). Both systems were used on most of the casings evaluated and only the G-3 system on several others. A following section of this Appendix describes the differences between these systems

Both are similar pulse-echo system designed to evaluate large volumes of material from a single test location. Initial development of these systems was focused detecting corrosion under insulation in petrochemical plant pipe-work, but it has since found widespread use in situations where pipes or tubes are not accessible, as occurs for buried or cased pipelines, or for elevated pipelines. This equipment is primarily considered as a qualitative long-range tool that will quickly and efficiently screen pipe segments to identify metal loss and discriminate between external and internal features plus an inferential assessment to identify coating loss and disbonded locations.

The main user expectation is a rapid, 100-percent coverage over long lengths of pipe to identify metal loss. Both systems are computer controlled, with data acquisition with data display and analysis being performed using a portable (laptop) personal computer (PC). As noted above, historically all applications of this technology were considered to require subsequent local investigation for quantitative data such as moderate and severe indications. The transducer and related signal conditioning and PC of the Teletest equipment are shown in Figure C1. This specific setup was used in Operator A's evaluation was similar.

Success in the use of LRGWUT technology depends highly on operator qualifications. Operator A's LRGWUT procedure provides minimum criteria for operator training. Prior LRGWUT work conducted by Operator A has demonstrated that proper operator qualifications are an essential element in achieving a successful result.


**Figure C1. Teletest signal conditioning and recording equipment**

Both systems employ low-frequency (in ultrasonic terms) guided waves that lie just above audible frequencies. These guided waves are propagated from a ring of transducers that is fixed

**Figure C2.  View of Teletest transducer set on a 12-inch diameter pipeline**

around the pipe, as illustrated by the Teletest equipment in Figure C2 and GUL G-3 equipment in Figure C3.  The use of low frequencies is necessary to generate the appropriate wave modes.  At such frequencies a liquid couplant is not needed between the transducers and the surface, with satisfactory ultrasonic coupling achieved via mechanical or pneumatic pressure applied to the back of the transducers to maintain contact with the pipe surface.  The uniform spacing of the ultrasonic transducers around the pipe circumference allows guided waves to be generated, which propagate symmetrically about the pipe axis.  These may be visualized as a circular wave that sweeps along the pipeline.  The full pipe wall thickness is excited by the wave motion, with the pipe wall acting as the wave-guide – hence the terminology guided wave UT.  The propagation of these guided waves is governed principally by the frequency of the wave and the material thickness.

Where the wave encounters detectable changes in pipe's wall thickness – be it an increase or a decrease – a proportion of the wave's energy is reflected back to the transducers, providing a means to detect discontinuities.  In the case of a pipe feature such as a girth weld, the increase in thickness is symmetrical around the pipe, so that the advancing circular wave front is reflected uniformly.  Thus the reflected wave is also symmetrical, consisting predominantly of the same wave mode as the incident wave.  In contrast, an area of corrosion is a decrease in thickness that is localized, leading to scattering of the incident wave, with reflection and mode conversion also occurring.  The reflected wave therefore consists of the incident wave mode plus the mode converted components.  The mode-converted waves tend to cause the pipe to flex as they arise from a non-uniform source.  The presence of these signals is a strong indicator of discontinuities such as corrosion.

Such technology is capable of detecting and distinguishing between symmetrical and flexural waves, with both types being displayed.  The reflections where the develop in response to changes in wall thickness are displayed as rectified signals in amplitude as a function of distance on an "A-scan" display, similar to that used in conventional ultrasonic practices, but with the time-base range being measured in tens of meters rather than centimeters.

A major complication for guided wave schemes as distinct from conventional ultrasonic technologies is the dispersive nature of guided waves. Therefore, the velocity of most guided waves varies with their frequency, which causes a variety of complications. The primary complication involves calibrating the time base of the A-scan to read distance rather than time, which requires a computer program to read in a velocity for the selected test frequency from a calibration, or "dispersion" curve. To address this, a library of dispersion curves are built into the system software that covers the practical range of combinations of pipe diameter and wall-thickness. Girth welds in the pipe produce dominant signals in the A-scan and act as important markers, which can be used to set a distance amplitude correction (DAC) curve on the display with which signals from anomalies can be compared, as discussed next in regard to signal interpretation.

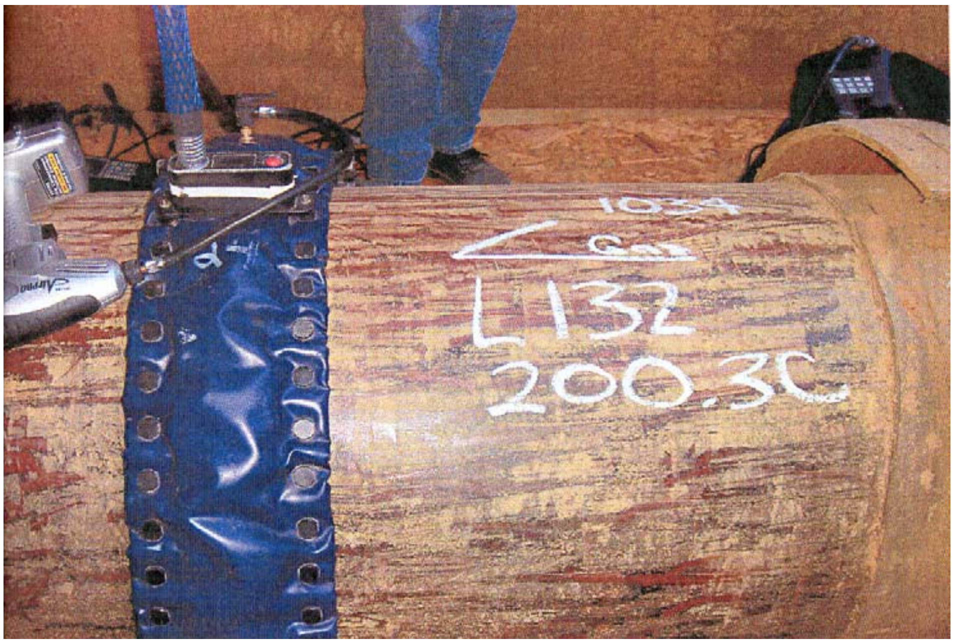


**Figure C3. GUL G-3 LRGWUT Transducer Installation on Large Diameter Pipe**

## "A-Scan" Display and Data Analysis

Before the signals on the A-scan can be interpreted, the DAC curves are placed on the display such as that the Teletest output illustrated here as Figure C4. The strength of all signals from reflections associated with changes in wall thickness decay with distance traversed, as does the incident wave, which as noted later limits the range of this technology.

Signals reflected from girth welds in the pipe are ideal reflectors by which to set the DAC. By experience it is known that the reflection from a girth weld with normal cap and root profile is 14dB (a factor of 5) less intense than the reflection from the pipe end (i.e. total reflection). While there is a small amount of variability from weld to weld, this level is consistently observed in practice. For the present work, this –14dB DAC curve appears as a blue line on the A-scan shown in Figure 2. Furthermore, experience also shows that an area of thinning that has resulted in a loss of cross-sectional area of 9-percent in the pipe wall will produce a signal that is 12dB below the girth weld signal for a total of 26 dB. This 26 dB decrease (i.e., –26dB) level is used as a threshold for evaluating signals, appearing as a green line on the A-scan. This level is used to rank indications on a relative scale from minor, through moderate, to sever. Signals that are close to, but do not break the –26dB curve are normally ranked “minor”, while signals that exceed the –26dB curve being ranked “moderate”, whereas signals that greatly exceed the –26dB curve to the extent that they reach the –14dB line, are ranked “severe”.  Thus, these -14 dB and -26 dB curves represent two important curves of the 4 DAC curves shown on the A-scan.

A third DAC shown on the A-scan is the 0 dB curve, which is presented as a black curve.  This signal develops from the near perfect reflector that exists at the end of a pipe end or at a flange, as can be demonstrated on a length of pipe in the laboratory, and so is used to set an absolute reference sensitivity.  The last curve shown on the A-scan represents –32dB response, which serves to determine the effective testing distance providing a signal to noise ratio of 6dB or better for a callable anomaly at -26dB.  This is the worst signal to noise ration that affords effective interpretation of the test data, effectively serving as the limit for both testing distance as well as sensitivity to smaller anomalies.

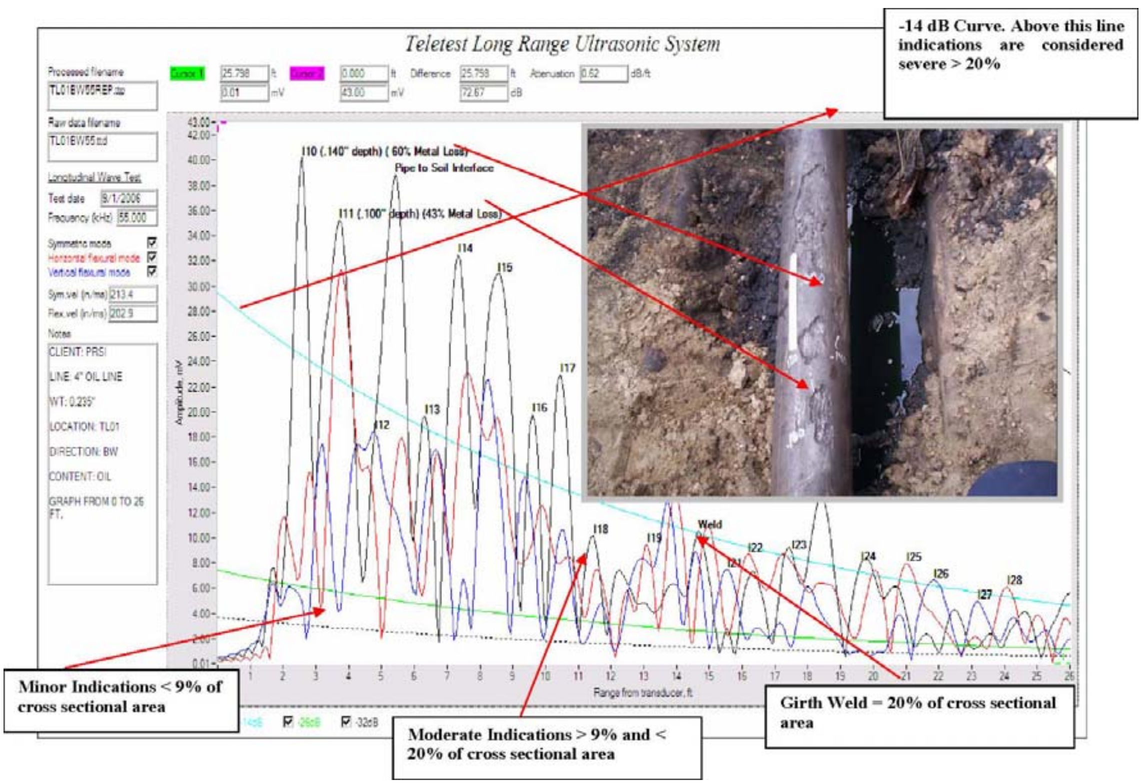


**Figure C4.  A-Scan Data Graph from Teletest (for the corroded pipeline in the inset)**

## Data Recording

The system  operator uses the A-scan display to interpret the data the results of which are imported into software resident on the PC, and presented in typical applications in the format of reports generated by the software.  Signals are recorded in the report as directed by the equipment operator.  The operator selects relevant signals in the A-scan using the screen-cursor and the software automatically measures the peak of the signal as a value above or below the 14dB DAC curve, and also measures the distance of the leading edge of the signal from the centre line of the transducer.  An offset also can be entered that allows distance to be measured from a known datum rather than from the transducer.

Reports also contain information about the test site, which is entered into a client page during set-up of the software, such as pipe identification, test location, and pipe size. Such a format has been used for Operator A's project. Such data recording and reporting is typically generated from the several processed data files gathered at each test location, and can contain results of observations comprising data generated and processed from files developed using a range of different test parameters, for tests at a range of ultrasonic frequencies.

## Defect Ranking

As noted above, LRGWUT signals are classified as "minor", "moderate", or "severe" and so must be reported in qualitative terms. There is a monotonic relationship between the amplitude of reflection from idealized flaws and their size, such that large reflections and signals develop at large artificial idealized flaws. However, the response from real flaws is much more complex. Therefore, while large responses are only likely to arise from large flaws, the converse is not necessarily true as the shape and orientation also affect the response amplitude. The -26dB line is the threshold reporting level, such that a signal exceeding this represents a response equivalent to an idealized 9-percent areal flaw. Because of the complexity of real defects and the fact that the shape and orientation of defects also affect the amplitude of the signal leading to a relative classification (minor to severe) that such LRGWUT systems must be viewed as screening tools. In turn, it is for this reason that follow-up with more quantitative NDT can be warranted.

Given the qualitative ranking via LRGWUT, the reporting of a severe reflector denotes the likely presence of large flaw that can be taken as a metric to validate the presence of an immediate indication from an AC-based DA-tool. The reporting of a minor reflector indicates that a signal was observed that did not break the threshold level for a 9-percent areal defect. Such indications are reported because for some applications detection of small flaws is desirable and it may be required to monitor the area for possible growth of such features over time. Thus, a minor reflector denotes the likely presence of a small defect that can be taken as a metric to validate the presence of a monitored indication from an AC-based DA-tool. It follows then that a moderate reflector denotes the likely presence of a defect that can be taken as a metric to validate the presence of a scheduled indication from an AC-based DA-tool. As time passes and more experience is gained with LRGWUT tools, and these tools improve still further, this relative ranking could be refined. But, even with those improvements it is likely that interpretation of the particular LRGWUT system responses as well as those of other such tools will require a thorough understanding of the technology and the many factors that influence the test output.

## Teletest and GUL G-3 Comparison

Operator A conducted LRGWUT evaluations of cased crossing using both of these commercially available systems. In a majority of the locations, both systems were used to conduct an inspection of the same casing while pipe in several other casings was inspected only with the G-3 system

Both systems are computer controlled the ultrasonic transducers mounted in one or more inflatable collars for mounting on larger diameter pipe. Both use torsional and longitudinal ultrasonic waves and the G-3 system also offers a C-Scan capability. The G-3 system has a built in GPS unit while this is optional on the Teletest system. The reported complete system costs for both systems is essentially the same

The G-3 system is reportedly easier to set up and offers more user friendly software as compared to the Teletest system thus equating to higher inspection productivity.  Some disadvantages of include slow support by GUL and equipment reliability issues with Teletest.  A major factor contributing to a successful inspection using both LRGWUT systems is operator qualification. Properly trained operators are an essential element.

Achievable inspection distances from the transducer collar location are the same for both systems depending on the coating that are about 90 feet for buried coal tar/asphalt coated pipe and up to about 100 for buried FBE coated pipe.  The inspection distance for above ground bare pipe is up to 300 feet.

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# Appendix D: Operator B ECDA Protocol[1]

## 1.0 PURPOSE

This protocol is a template for use or revision by Operator B being developed for the Direct Assessment Project (hereafter Project). It is intended to serve as a general guide for properly conducting the External Corrosion Direct Assessment (ECDA) to ensure that the data collection and analyses conducted meet the Project's objectives. It also serves as a guide for use in the training done as part of the Project.

The requirements contained in this protocol may for this specific project maybe modified by the Field Contractor provided such modifications meet or exceed the provisions of this document and are approved by Battelle for this specific contract, and Operator B in future applications of ECDA. This protocol is intended to assure that the four primary steps in the ECDA process are properly performed to provide a reliable pipeline integrity estimate. It does not contain detailed procedures to guide the field work. Such procedures will be specified by the field contractor consistent with their experience and practices in applicable to the particular site conditions. By virtue of its design as only a protocol, this document does not stipulate all of the requirements and tasks consistent with NACE RP 0502 and by itself does not guide field implementation practices and criteria, which comprise the procedure for conducting an ECDA.

## 2.0 INTRODUCTION

### 2.1 Project Overview

ECDA is a four step process conducted to assess the integrity of a pipeline primarily where external corrosion has been determined to be a primary threat. The four ECDA process steps are: pre-assessment, indirect inspection, direct examination, and post assessment. Pre-assessment includes data collection and review which is an essential component in this process and must be comprehensively completed. Indirect inspection and direct examination comprise the process steps completed in the field. Post assessment characterizes pipeline structural integrity and determines re-inspection intervals. ECDA is often conducted on pipelines where other integrity assessment methods may also not be feasible. ECDA also can be applied along with other integrity assessment methods including ILI and hydrotesting.

### 2.2 Participating Service Provider Responsibilities

#### 1.2.1 General Requirements

As with any integrity management practice, it is important that the work be conducted according to an established protocol so that the results are credible and can withstand question by Operator B's corporate stakeholders as well as the public or regulatory bodies. For this reason, the ECDA project shall be conducted in accordance with the requirements of this protocol with activities or analyses that meet or exceed the stated requirements considered to be acceptable. Should service providers take exception with the provisions of this protocol, Operator B must be provided a written notification in advance, including justification for their request along with a documented

[1] This version is sanitized and somewhat adapted to reflect sensitivities in its release.

and proven alternative protocol or activity that has been fully field demonstrated and proven. Written acceptance by Operator B is required prior implementing such a protocol modification.

### 1.2.2 Additional Data Collection, Tests and Evaluations

In some cases, meeting Project objectives will require additional data, direct examinations, tests, and evaluations as requested in writing by Operator B as a rider to the procurement document. If the service provider feels that the request is incompatible with his anticipated procedures and practices, such must be clearly stipulated by the provider in his bid-package, along with the implications for Project success within time and budget.

### 1.2.3 Definitions

The following are definitions of some key terms used in this protocol:

**Shall:** Is a requirement that must be complied with or its exception approved and documented in accordance with Section 7.0 of this protocol.

**Should:** Is a recommendation that is desirable to follow if possible. Not following the recommendation does not have to be documented or approved.

**Required:** "Required" data listed in Table C3.1 must be obtained or its omission is approved and documented in accordance with Section 7.0 of this protocol.

**Desired:** "Desired" data listed in Table C3.1 should be obtained if it is documented or easily measured. Its omission is not required to be approved or documented.

**Considered:** "Considered" is a recommendation that a data element is taken into account for the selection of indirect inspection tools, ECDA regions, or analysis of test results.

**ECDA Region:** Pipeline segments that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and be suitable for application of the same two indirect inspection tools. A single ECDA region can be comprised of non-contiguous pipeline segments.

**Bellhole:** Excavation site that facilitates direct examination, maintenance, repair, or replacement of pipe sections.

**Calibration Dig:** Exploratory excavations, or bellholes, conducted at sites not identified by Direct Assessment for control purposes (e.g. "False negative" indications).

**Characterize:** Process of quantifying the type, size, shape, and/or orientation of an anomaly.

**Classify:** To determine whether a signal is an anomaly or non-relevant condition.

**Holiday:** A discontinuity or break in a coating, such as a pinhole, crack, gap, or other flaw, that allows the base metal to be exposed to any corrosive environment that contacts the coating surface. See also disbonded coating.

**Microbiologically Induced or Influenced Corrosion (MIC):** A type of corrosion that results from certain microbes in the soil.

**Signal:** Any measured response from an indirect examination above the normal baseline signal.

**Verification Dig:** Exploratory excavations, or bellholes, at sites identified by Direct Assessment to determine the existence, size, or severity of pipeline and other conditions.

## 3.0 PRE-ASSESSMENT

### 3.1 Objectives

A key aspect of the pre-assessment step is the collection of pipeline data. Table C3.1 PRE-ASSESSMENT DATA provides a checklist of the data elements needed to conduct the ECDA. The source of these data requirements is NACE RP 0502-2002. This project will utilize the IMP to gather this data to achieve the following objectives:

- Collect the needed pipeline data to in accordance with Table C3.1;
- Determine the feasibility of conducting an ECDA of the assessment area;
- Select Indirect Inspection Tools (IIT);
- Establish ECDA regions;
- Document pre-assessment results.

### 3.2 Data Collection

The “Need” for the data elements is identified in Table C3.1 as either “REQUIRED” or “BENEFICIAL”. Data in both categories are essential for a successful ECDA process. Information collected shall include data in all five categories shown in Table C3.1.

**Table C3.1: Pre-Assessment Data List**

| ID Number | Data Element | Need |
|---|---|---|
| **1.0 Pipe Related** | | |
| 1.1 | Material and Grade | Required |
| 1.2 | Diameter | Required |
| 1.3 | Wall thickness | Required |
| 1.4 | Seam Type | Beneficial |
| 1.5 | Bare pipe | Beneficial |
| **2.0 Construction Related** | | |
| 2.1 | Year installed or commissioned | Required |
| 2.2 | Construction practices | Beneficial |
| 2.3 | Locations of casings | Required |
| 2.4 | Location of bends, including miter bends and wrinkle bends | Beneficial |
| 2.5 | Underwater sections and river crossings including weight coatings and river weights | Required |
| 2.6 | Proximity to other pipelines structures, HV electric transmission lines and rail crossing | Required |
| 2.7 | Locations of laterals, crossovers, or other underground appurtenances (i.e. drips). | Required |
| 2.8 | Depth of cover | Required |
| **3.0 Soil/Environment** | | |
| 3.1 | Soil characteristics & types. | Beneficial |

| ID Number | Data Element | Need |
|---|---|---|
| 3.2 | Land use (current/pass) | Beneficial |
| **4.0 Corrosion Control** | | |
| 4.1 | CP system type (anodes, rectifiers and locations) | Required |
| 4.1 | CP system type (anodes, rectifiers and locations) | Required |
| 4.2 | CP evaluation criteria | Required |
| 4.3 | CP maintenance history | Beneficial |
| 4.4 | Years without CP applied | Beneficial |
| 4.5 | Coating type-pipe | Required |
| 4.6 | Coating type-joints | Beneficial |
| 4.7 | Coating condition | Required |
| 4.8 | CP survey data/history | Beneficial |
| **5.0 Operational Data** | | |
| 5.1 | Operating stress level/temperature | Required |
| 5.2 | Leak/rupture history (EC) | Beneficial |
| 5.3 | Evidence of external MIC | Beneficial |
| 5.4 | Type and frequency of third party damage | Beneficial |
| 5.5 | Data from previous over the ground surveys | Beneficial |
| 5.6 | Hydro test dates/pressures | Beneficial |
| 5.7 | Pipe inspection reports, repair/maintenance history | Beneficial |

## 3.3 Indirect Inspection Tool (IIT) Selection

### 3.3.1 Number of IIT's

Where data collection and evaluation have established that the ECDA process is feasible, the Service Provider shall select at least two complimentary indirect inspection tools from Table C3.2 or proven equivalents for each that are suitable for the established ECDA regions in the pipeline or segment being evaluated. Where tools other than those listed in Table C3.2 are considered, the Service Provider shall use the exception process described in Section 7.0 of this protocol.

In addition to the two primary IIT's, the Service Provider may select additional indirect inspection tools to compliment the two primary IIT's to obtain additional data concerning coating defects that may contain external corrosion. The Project may also request additional IIT's to supplement the Service Provider's assessment.

### 3.3.2 Selection Documentation

The selection of IIT's shall be documented for each ECDA region in pipeline segment being evaluated. The documentation shall include the name and description of each technique used, the selection rationale, and any special considerations (including limitations) for conducting the indirect inspections. Form B, Indirect Inspection Tools Selection should be used to document the IIT selections. Justification for IIT selection in each region shall also be documented.

**Table C3.2: ECDA Tool Selection Guidance**

| Conditions | CIS | DCVG/ACVG | Electro-magnetic (PCM) |
|---|---|---|---|
| Coating holidays | Yes | Yes | No |
| Anodic zones on bare pipe | Yes | No | No |
| Near river or water crossings | Yes | Possible | Yes |
| Under frozen ground | No | Yes | Yes |
| Stray currents | Yes | Yes | Yes |
| Shield corrosion activity | No | No | No |
| Adjacent metallic structures | Yes | Yes | Yes |
| Near parallel pipe lines | Yes | Yes | Yes |
| Under HVAC electric transmission lines | Yes | Yes | No |
| Shorted casing | Possible | Possible | Possible |
| Under paved roads | Possible | Possible | Yes |
| Uncased crossings | Yes | Yes | Yes |
| Cased crossings | No | Possible | Yes |
| Wetlands | Yes | Yes | Yes |
| Rock terrain, ledges or backfill | Possible | Possible | Yes |

## 3.4 Establishment of ECDA Regions

### 3.4.1 Description

ECDA Regions are pipeline segments that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and permit the use of the same indirect inspection tools. An ECDA region is not necessarily comprised of a contiguous pipeline segment. Pipeline features such as cased crossings require more specialized analysis methods and modified application of techniques included in Table C3.2. Therefore, they may not require designation as unique ECDA regions.

### 3.4.2 Criteria

The Service Provider shall analyze all the data collected in the Pre-assessment step and assign each pipeline segment to an ECDA region consistent with the Project's objectives and work-plan. The Service Provider shall indicate the criteria used for selecting ECDA regions.

### 3.4.3 Documentation

Each ECDA Region description shall be defined and documented on Form A (ECDA Region Report). Each ECDA region shall have the two IIT's and at least one other characteristic to describe the ECDA Region. The Service Provider shall list all essential characteristics for each region.  The ECDA Region Report shall be provided to the operator as part of the reporting process.

# 4.0 INDIRECT INSPECTION

## 4.1 Objectives

The objectives of the Indirect Inspection process are to:

- Accurately locate and define the severity of coating faults, other anomalies, and areas where corrosion may have occurred or be occurring.
- Conduct at least two designated primary indirect inspections over the entire length of each ECDA Region.
- Align and compare the results from the inspections.
- Identification and classification of indications.
- Analyze and report results for the Direct Assessment step.

## 4.2 Conducting Indirect Inspections

### 4.2.1 Breadth of Inspections

Each of the two designated primary indirect inspections as designated in the pre-assessment step shall be conducted over the entire length of each ECDA region.

### 4.2.2 Additional Indirect Inspections

Indirect inspections in addition to the two primary specified methods may be conducted in specific areas as determined by the Service Provider.  Such inspections may be used to resolve any discrepancies between results of the two primary methods or be dictated by field conditions present.  Results of additional inspection(s) shall be documented in Form B, Indirect Inspection Tool Selection.

### 4.2.3 Time between Primary Inspections

The Service Provider shall conduct the two indirect inspections for an identified ECDA region as close in time as reasonably possible.  In no case shall the time interval between these indirect inspections exceed 90 days.  If this interval is exceeded, or the local pipeline right-of-way conditions have significantly changed since completion of the first indirect inspection, comparison of indirect inspection results may be invalid.  Any modification of this requirement shall be agreed to in accordance with the Exception Process contained in Section 7.0 of this protocol.

## 4.3 Indirect Inspection Reporting Content

It is essential that the results of two primary indirect inspection tools and any additional tool results can be accurately aligned and compared to properly classify the severity of each indication.  Accurate indirect inspection location data is also required to facilitate comparison to other integrity data such as in-line inspection (ILI) results where ECDA is being done to supplement ILI data or capture corrosion defect growth rate data.  Methods used to account for and reduce the spatial error during data alignment shall be completely documented.  Locations should be referenced to precise geographical control points, fixed pipeline components, and/or GPS coordinates.  The IIT report shall contain the following:

### 4.3.1 Location and Dates

Description of the location where the indirect inspections were performed as well as the dates they were conducted.

### 4.3.2 Indirect Inspection Tools Used

Description and results of all indirect inspection tool results and data plus evaluation/interpretation criteria. Results of other tests performed such as soil resistivity, depth-of-cover, ILI data, and other integrity related surveys should also be included. Necessary data integration and alignment criteria should also be included.

### 1.3.3 Survey Plots

Data collected during the ECDA surveys shall be formatted to facilitate plotting of all IIT results with stationing indicated at a maximum of 100-foot intervals. Landmarks shall be noted on the chart as well as other test data such as depth-of-cover surveys, soil resistivities, ILI data, CP test points, and other integrity related data. The date when the tests were conducted shall also be included on the plots.

### 4.3.4 Electronic Format

Data shall be provided in an electronic database format to facilitate integration, alignment, analysis, and plotting.

## 4.4 Identification and Classification of Indications

### 4.4.1 Objective

This section describes the requirements for identifying and classifying indications. The classification is the process of estimating the likelihood of corrosion occurring at each indirect inspection indication. To facilitate the classification process this section also provides an example classification criteria for the indications. Service Providers may use these criteria or select other criteria when they are classifying the indications. Any other classification criteria shall be submitted in writing to and approved by the operator prior to implementation.

### 4.4.2 Identification Criteria

The criteria used to identify and align indirect inspection indications shall be provided by the Service Provider for each IIT. Table C4.1 contains suggested identification criteria for several indirect inspection tools for the three defined security classifications. Application of other identification criteria shall be submitted in writing to and approved by the operator prior to implementation.

### 4.4.3 Classification Criteria

Each indication shall be initially classified by the Service Provider. Criteria for indirect inspection indication severity classification shall be provided in writing to the operator by the Service Provider for approval. Suggested classification criteria are provided in Table C4.1.

**Table C4.1: Suggested Classification Severity Guide**

| INDIRECT INSPECTION TOOL | CLASSIFICATION SEVERE INDICATIONS | CLASSIFICATION MODERATE INDICATIONS | CLASSIFICATION MINOR INDICATIONS |
|---|---|---|---|
| CIS | All of the following must exist:<br>Less than 600 mv off<br>200 mv depression over baseline<br>Convergence of on/off potential<br>Other condition that the Service Provider wants to document | All of the following must exist:<br>Less than 600 mv off<br>200 mv off depression over baseline<br>Other condition that the Service Provider wants to document | Any of the following can exist:<br>Between 600 to 850 mv off<br>Other conditions that the Service Provider wants to document |
| DCVG | 6 or more indication per 100 feet | 4 to 5 Indication per 100 feet | 1 to 3 Indication per 100 feet |
| PCM | Greater than 20% change in 100 feet | Not applicable | Between 10 and 20% change in 100 feet |
| ACVG | 6 or more indication per 100 feet | 4 to 5 Indication per 100 feet | 1 to 3 Indication per 100 feet |

### 4.4.4 Documentation

The severity classification of each indirect inspection indication shall be documented. The following information shall be provided for each indication:

- Inspection Tool: The indirect inspection technique used to identify the indication
- Location: The location of the indication along the pipeline
- Severity Classification: Whether the indication is minor moderate or severe

Form C, Indication Classification and Alignment Form, should be used to document the information listed above.

## 5.0 DIRECT EXAMINATION

### 5.1 Objectives

- The objectives of the Direct Examination process are to:
- Prioritize locations identified during indirect inspection for direct examination;
- Excavation of locations and in-ditch data collection;
- Complete remaining strength evaluation;
- Conduct root cause analyses;
- Complete in-process evaluations including indication severity reclassification and reprioritization
- Determine the number of excavations;

### 5.2 Prioritization of Indirect Inspection Indications

Prioritization is the process of ranking the indirect inspection indications based on their need for additional evaluation by excavation and direct examination of the pipe surface. Prioritization is a two-step process where indications are initially prioritized by aligning and integrating the data from the individual indirect inspections. The prioritization can then be updated or changed if necessary with the additional integration of data and analysis results from the direct examination step of the ECDA process.

### 5.2.1 Initial Priorities

The indications shall be initially prioritized as Immediate, Scheduled, or Monitored in accordance with NACE RP 0502-2002 and the following minimum criteria. Table C4.1 illustrates an example prioritization criterion for two different combinations of indirect inspection tools.

5.2.1.1 Immediate

This priority should include indications that are likely to have on-going corrosion activity and that, when coupled with past corrosion could pose a threat to the pipeline segments operating above 30-percent SMYS. Indications that follow in this priority are:

**Isolated Indications**: Indications that were prioritized as severe by either or both IIT inspections as shown in Table C4.1.

**Multiple Severe Indications**: Multiple severe indications that are in close proximity and interaction between indications should be considered during data analysis.

**Discrepancies Between IIT**: Indications that have unresolved discrepancies between the two primary IIT techniques that have not been resolved by additional indirect inspection or other methods.

**Prior Corrosion Zones**: Other severe or moderate indications that are known to have significant corrosion based on historical data.

**Difficult to Characterize Indications**: Indications where the likelihood of corrosion activity or severity cannot be characterized such as indications that are a result of interference with CP current.

5.2.1.2 Scheduled

This priority should include indications that may have on-going corrosion activity but, when coupled with prior corrosion history, do not pose a threat to the pipeline segments operating below 30-percent SMYS. Indications that fall into this priority are:

- **Severe Indication**: Severe indications that are not in close proximity with other severe indications and were not prioritized as Immediate in accordance with the criteria in Section 5.2.1.1. See Table C4.1.
- **Moderate Indications**: Moderate indications that had prior significant corrosion likely at or near the indication.

5.2.1.3 **Monitored**

These indications are minor and have the lowest likelihood of being active. See Table C4.1.

### 5.2.2 Documentation

The prioritization criteria, if different than above, shall be documented in writing and provided to the Project for approval prior to implementation. The Service Provider shall assign a priority based on the approved prioritization criteria to each indirect inspection indication and provide it to the Project. Form C should be used to document the prioritization of indications.

### 5.2.3 Indirect Inspection Analysis

The Service Provider shall compare the results of the indirect inspections with the pre-assessment results and prior history for each ECDA region to see if they are rational. If the assessment results are not consistent with operating history, the Service Provider must reassess the feasibility of the ECDA.

## 5.3 Direct Examination Excavations

The exploratory excavations conducted during the Direct Examination step are used to calibrate and validate the prioritization of indications and severity estimates from the indirect inspection step.

### 5.3.1 Number of Excavations

The numbers of excavations discussed in the following paragraphs are the requirements of NACE RP 0502-2002. They are governed by the number, and priority of the indications, as well as if it is the first ECDA project conducted on the pipeline or segment being evaluated. Table C5.1 provides a summary of the number of required excavations.

5.3.1.1 <u>Immediate Indications</u>

All immediate indications shall be excavated.

5.3.1.2 <u>Reprioritization</u>

If Immediate indications are reprioritized to a lower priority due to the results of Direct Examinations as described in §5.6 they shall follow the excavation criteria for that lower priority.

5.3.1.3 **Scheduled Indications**

A minimum of one Scheduled indication shall be excavated per ECDA region. A minimum of two Scheduled indications shall be excavated per ECDA region for the first ECDA project.

5.3.1.4 <u>20-percent Wall Loss Criteria</u>

If 20-percent or more wall loss is found at a Scheduled indication then the Service Provider shall continue to excavate Scheduled indications in order of priority until at least two Scheduled indications exhibit less than 20-percent wall loss.

5.3.1.5 <u>Reprioritization</u>

If Scheduled indications are reprioritized as described in Paragraph 5.6 then they shall follow the excavation criteria for that priority. If one or more Scheduled indications are reprioritized to Immediate, then there shall be at least one more excavation per ECDA Region of a Scheduled indication.

### 5.3.2 Monitored Indications

Monitored indications are not required to be excavated and can be either monitored or reprioritized as described in Paragraph 5.6. However, if an ECDA Region did not have any Immediate or Scheduled indications than at least one Monitored indication shall be excavated.

### 5.3.3 ECDA Effectiveness Digs

One additional excavation is required to assess the ECDA evaluation process. The location shall be at the next most severe scheduled indication or if there are no remaining scheduled indications it will be at the most severe monitored location.

### 5.3.4 Initial ECDA Projects

Two additional excavations shall be conducted on initial ECDA projects. One excavation shall be at a Scheduled indication and the other where no indirect inspection indications were detected. Additional excavations at such locations may be requested by the Project.

**Table C5.1: Summary of Required Excavations**

| Priority of Indications Found | | | Required Excavations | | | Requirements for additional excavations | Additional Excavations | | | | | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| I | S | M | I | S | M | | I | S | M | DA Application | | |
| | | | | | | | | | | Initial | Subsequent | |
| X | | | All | | | | | | | 2 | 1 | |
| X | X | | All | 1 | | 1st ECDA | | 1 | | 2 | 1 | |
| | | | | | | Scheduled reprior. to Immediate | | 1-2 | | 2 | 1 | Two excavations are required for 1st ECDA |
| X | X | X | All | 1 | | 1st ECDA | | 1 | | 2 | 1 | |
| | | | | | | Scheduled reprior. to Immediate | | 1-2 | | 2 | 1 | Two excavations are required for 1st ECDA |
| | X | | | 1 | | 1st ECDA | | 1 | | 2 | 1 | |
| | | | | | | Scheduled reprior. to Immediate | | 1-2 | | 2 | 1 | Two excavations are required for 1st ECDA |
| | X | X | | 1 | | 1st ECDA | | 1 | | 2 | 1 | |
| | | | | | | Scheduled reprior. to Immediate I | | 1-2 | | 2 | 1 | Two excavations are required for 1st ECDA |
| | | X | | | 1 | 1st ECDA | | | | 2 | 1 | |
| No Indications | | | 1 Excavation based on Pre-assessment | | | 1st ECDA | 1 Excavation based on Pre-assessment | | | 2 | 1 | |

### 5.3.5 Scheduling of Excavations

In order to complete the Project in a timely fashion consistent with the operator's expectations and the requirements contained in this protocol, the Service Provider is to have all excavations completed prior to the rainy season of 2006.

## 5.4 Data Collection During Excavation

### 5.4.1 Procedure

The Service Provider shall provide the project the procedure and the data elements that will be collected during Direct Examination.

### 5.4.2 Data Collection

The collection of data on the condition of the coating and the pipe during an excavation is a key ECDA process element. Table C5.2 summarizes the data to be collected during the Direct Examination. The data elements listed as "Requested" are the highest priority and the items listed as optional are secondary.

**Table C5.2: Requested Data Collected During Direct Examination**

| Data Element | Data Type | Category | Description |
|---|---|---|---|
| **6.0 Before Coating Removal** | | | |
| 6.1 | Measurement of pipe to soil potential | Requested | These measurements shall be performed in accordance with NACE Standard TM0497. The reference electrode shall be placed in the bank of the excavation and/or at the ground surface. These potential may help identify dynamic stray currents. |
| 6.2 | Soil Resistivity | Requested | Soil resistivity measurements shall be taken near the pipe but no closer than half of the pin spacing on the soil resistivity measurement device |
| 6.3 | Soil Sample | Optional | Soil immediately adjacent to the pipe surface shall be collected with a clean spatula or trowel and placed in an 8 oz. plastic jar with a plastic lid. The sample jar should be packed full to displace as much air as possible. Tightly close the jar, seal with plastic tape and using a permanent marker to record the sample location on both jar and lid. |
| 6.4 | Ground Water Samples | Optional | Take ground water sample if water is present in excavation. Water should always be collected from the open ditch when possible. Completely fill the plastic jar and seal and identify location as described above. |
| 6.5 | Coating Condition | Requested | Documentation of general coating condition. Three conditions could exist 1) Coating is in excellent condition and completely adhered to pipe. 2) Coating partially disbonded and/or degraded. 3) The coating is completely missing the pipe surface is bare |
| 6.6 | Photo Documentation | Requested | Document the coating condition with digital camera. Photos shall have ruler or other device to determine magnification of photographs showing details of the pipe and coating condition. Macro as well perspective views shall be recorded. |
| 6.7 | Coating Sample | Optional | A sample of the coating shall be obtained if the coating is partially or fully disbonded. This sample will be used to determine the electrical and physical properties of the coating as microbial tests. |

| Data Element | Data Type | Category | Description |
|---|---|---|---|
| 6.8 | Under coating liquid pH analysis | Requested | If any liquid is detected underneath the coating the pH shall be determined with pH litmus tape. |
| 6.9 | Corrosion Product Removal | Requested | Carefully remove any corrosion deposit for analysis |
| **7.0 After Coating Removal** | | | |
| 7.1 | Pipe Temperature | Optional | Measure the bare pipe surface temperature. |
| 7.2 | Weld Seam Identification | Optional | The type of weld seam shall be identified and recorded. |
| 7.3 | Other Damage | Requested | Other damage to the pipe surface that can be visual detected shall be recorded. Examples of such damage would include gouges, cracking, dents and out of roundness. |
| 7.4 | Identification of Active or Inactive Corrosion | Requested | Careful examination of the corrosion surface shall be conducted after some cleaning to determine if corrosion is active or inactive by visual examination of the corroded surface at low magnifications. |
| 7.5 | UT Wall Thickness Measurements | Requested | Ultrasonic wall thickness shall be taken at every quadrant on the pipe to establish original/nominal wall thickness. |
| 7.6 | Photographic Documentation of Corroded Area | Requested | The corroded surface shall be photographed, preferable with a digital camera to document the morphology. |
| 7.7 | Mapping and measurement of corrosion areas | Requested | Corrosion damage shall be measured sufficiently to enable accurate analysis of the corrosion area and remaining strength (ASME B31G or RSTRENG). A grid of wall loss measurements shall be taken over the entire corroded areas. The grid shall be oriented so that columns are circumferentially oriented on the pipe and the rows lie parallel to the longitudinal axis of the pipe. The grid size should be sufficiently fine to document the variation of wall thickness but in no case shall be greater than a one-inch mesh. |
| 7.8 | Pit Depth Map | Requested | Record the pit depths of the corroded area in a matrix format with mesh spacing no greater than 1-inch. |

### 5.4.3 Additional Data Collection

To facilitate the analysis of data the Project may request additional data be collected during the direct examination excavations.

### 5.4.4 Documentation

The Service Provider shall document all the observations, measurements and tests conducted during the Direct Examination. Form D, Direct Examination Data Report should be used to report this data.

## 5.5 Root Cause Analysis

The Service Provider shall attempt to determine the root cause of all significant corrosion activity observed at Immediate and Scheduled indications. On older pipelines, exact determine of root cause may be impractical or impossible. Identifying the root cause will assist in conducting the analysis of the project.

### 5.5.1 Documentation

The root cause of the external corrosion (if determinable) for each Immediate or Scheduled indication should be documented by the Service Provider.

### 5.5.2 Evaluation of other Threats

If the root cause analysis identifies particular threats or degradation mechanisms that the ECDA process is not well suited to detect then it should be documented and provided to the project. NACE RP 0502-2002 requires a suitable assessment method be used to evaluate the segments of pipe for the degradation mechanism identified by the root cause analysis. Such an assessment methods must be submitted in writing to Operator B and approved prior to implementation.

## 5.6 Reclassification and Reprioritization of Indications

### 5.6.1 Overview

The additional data collected from the direct examination and the resulting analyses shall be used to determine if the indirect inspection severity classification and subsequent direct examination prioritization procedures have properly estimated the indication severity. This evaluation may result in indications being raised or lowered in priority as well as be classified as non-reportable indications.

### 5.6.2 Reprioritization Criteria

The Service Provider shall provide the Project a written criteria and process for reprioritizing the indications.

### 5.6.3 Reprioritization Requirements

The following requirements or allowances shall be applied to the reprioritization of indications.

5.6.3.1 <u>Corrosion More Severe Than Expected</u>

The Service Provider is required to reprioritize indications when severe corrosion is found and analysis (per ASME B31G or RSTRENG or agreed to equivalent to be approved by operator) requires the need for immediate remedial action.

5.6.3.2 <u>Reevaluation of Indications</u>

When an indication is raised in priority, the Service Provider shall re-evaluate other indications that have been assigned the same classification.

5.6.3.3 <u>Remediation</u>

If remediation is performed on an indication, it may be moved to the next lower classification provided post-excavation (local) indirect inspection justifies reducing the severity.

## 6.0 POST ASSESSMENT

### 6.1 Purpose

The purpose of the Post Assessment step is to determine the remaining life and reassessment intervals for an ECDA Region and to determine the overall effectiveness of the ECDA process.

### 6.2 Remaining Life Calculation

NACE RP 0502-2002 requires all excavated indications where corrosion was present have remaining life calculated. This section describes the requirement in making that calculation.

#### 6.2.1 Assumed Flaw Size

The maximum remaining flaw size at all excavated indications shall be used as a basis for remaining life calculations.

6.2.1.1 Root Cause Analysis Exception

If the root cause analyses indicate that the most severe indication is unique, the size of the next most severe indication may be used for the remaining life indication.

#### 6.2.2 Corrosion Rate

In the absence of other valid corrosion rate measurements, NACE RP 0502-2002 suggests the use of a constant corrosion rate for determination of remaining life.

6.2.2.1 Corrosion Rate Exceptions

Other data that are scientifically justified may be substituted such as determined from buried corrosion coupons or linear polarization probes representing conditions similar to the ECDA region(s) being considered.

6.2.2.2 Documentation

The Service Provider shall provide written documentation of the corrosion rate applied in remaining life calculations and justification for its application to the Project Team.

#### 6.2.3 Remaining Life Determination

The following remaining life determination method described in NACE RP-0502-2002 may be applied. Alternative methods utilizing industry accepted engineering practice may also be applied. The Service Provider shall provide written documentation that includes complete justification for any proposed alternative method to the Project.

$$RL = C * SM * \frac{t}{GR}$$

where:

- C = Calibration factor = 0.85
- RL = Remaining Life
- SM = Safety Margin = Failure Pressure Ratio – MAOP Ratio (Note: The SM formulation in RP 0502-2002 is incorrect)

Failure

- Pressure Ratio = Calculated Failure Pressure/yield pressure (dimensionless)
- MAOP Ratio = MAOP/yield pressure (dimensionless)
- t = nominal wall thickness
- GR = corrosion rate (in/yr)

6.2.3.1 Documentation

The Service Provider shall provide the project team the calculations used to determine the remaining life of each ECDA region. Form E: Remaining Life Calculation Report shall be used to document the calculation.

### 6.3 Reassessment Interval

RP 0502-2002 requires the maximum reassessment interval of indications not to exceed one-half of the remaining life of the scheduled indications.

#### 6.3.1 Other Reassessment Interval Limitations

Other reassessment interval restriction criteria contained in ASME B31.8S, ASME B31.8, or ASME B31.4 should be considered as applicable.

#### 6.3.2 Documentation

The Service Provider shall provide written documentation justifying the reassessment interval applied to each ECDA region to the Project.

## 7.0 EXCEPTION PROCESS

### 7.1 Expectations

It is expected that all requirements of this protocol and NACE RP502 be met in conducting an ECDA. However, when this is not possible then exceptions can be taken by documenting the exceptions as prescribed in this section.

### 7.2 Objective

The purpose of this section is to provide the required content for documentation of exceptions taken to this protocol. This documentation is to maintain the integrity of the analysis of the ECDA project.

#### 7.2.1 Section of Protocol

State the specific paragraph number where the exception is being taken, and indicate the exception, its cause, scope, and its implications.

#### 7.2.2 Alternative Plan

State what is proposed or done instead of what is required in the protocol.

#### 7.2.3 Justification

Provide documentation directly justifying the utility of the alternative.

#### 7.2.4 Notification

As soon as possible notify the the operator Project Manager of the exception.

### 7.2.5 Documentation

Document the above steps on Form F; Exception Report, and send to the Program Manager for his concurrence and signature.

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# Appendix E: Statistical Analyses of Casing ECDA Data

This Appendix describes the statistical analysis technique used to analyze Operator A's results

The problem of determining detection rates requires large samples (i.e., hundreds or thousands of samples) in order to have tight confidence bounds (5-percent or less) on the estimate. For example if a sample of 50 has 45 successes, even though the measured detection rate is 0.9, the actual detection rate is somewhere between 0.8 and 0.96 with a 95-percent level of confidence.

A different approach for small samples is to test whether the methodology has a statistically significant effect or not. For example one could test the hypothesis that a DA detection method is no better than random choice against the hypothesis that, indeed, the method can detect defects. The collected data can be presented in a contingency table, A common test used with contingency tables is the Chi-square test of independence. This test requires that each cell in the table shown in Tables E1 and E2 has at least five entries in order for the underlying assumptions to be valid. Naturally more samples will give better results. We suggest at least 10 cells in the true positive/true negative positions.

Several points should be noted.

1. The user must select random samples for whole row at a time, not cell-by-cell. The user will select random samples for each row, which will split into the two columns upon comparison with truth. Thus for an effective method to give five false positives or negative, more that 15 total samples will likely need to be drawn from each row.
2. Both rows and columns are essential to assess the ability of a method to discriminate. If only suspected problem areas are included there is no sense of how well the method will determine good areas to be good. One problem with looking only at bad areas is that the strategy of declaring everything to be a defect appears to be superior. Obviously it is not when that strategy is applied to good pipeline.
3. The proposed sample sizes are guidelines. With less than 5 samples in one cell, corrective methods can be employed. There are specialized "exact" methods that can be employed when many cells are less than five. The problem with small samples, however, is that it becomes very difficult to assert that the results seen are not due to chance. Thus small samples are not a problem from the point of view of doing analysis, but the results of the analysis are more likely to assert that DA is no different than random choice.
4. The choice of 10 in the diagonal cells (True Positives and True Negatives) comes from the number needed for the Chi-square test to assert there is a non-random effect of DA if the other cells had counts of five. Strictly speaking a table with entries of 10, 5, 5, 10 will not just barely not pass the test, but if either of the 10's were an 11, it would. So 10 provides a good rule-of-thumb and as noted in point 1 above, in order to get a 5 in the off-diagonal cell a sample of more than 15 for each row will very likely need to be collected.

To illustrate, consider the following hypothetical data and the conclusions that could be drawn using them. Examples 1 and 2 both show total samples of 40 points, with 20 positive and 20 negative indications. Both were constructed with DA appearing to be effective in the sense that the True Positive/True Negative counts are higher than the False Positive/False Negative counts. A Chi-square test of independence was applied to each and the result is a p-value. P-values less than 0.05 are indicative that the data seen are not due to random chance and support the claim that DA is working. (Or, in technical terms, if $p < 0.05$ then we reject the null hypothesis which is the result is due to random chance.) In the first example, the data support the claim that DA is finding defects as $p = 0.0044$ which is less than 0.05. In the second example $p=0.11$ and the data are consistent with random results. Please note that this does not mean the results are random, merely that the data does not assert that there is any reason to claim otherwise. With a larger sample and data in the same proportions it might be possible to reject the assertion that results are random.

**Table E1. Contingency Tables**

**Example 1: 2 x 2 Contingency Table -Example 1:**

| | **Actual** | | |
|---|---|---|---|
| DA | | Positive | Negative |
| | Positive | 14 | 6 |
| | Negative | 5 | 15 |

p=0.0044

**Example: 2-2 x 2 Contingency Table - Example 2:**

| | **Actual** | | |
|---|---|---|---|
| DA | | Positive | Negative |
| | Positive | 12 | 8 |
| | Negative | 7 | 13 |

p=0.11

# Appendix F: Operator A Casing ECDA Data Summary

The data set in shown in Table F1 includes 58 inspection results using the PCM and PCM + ACVG indirect inspection methodology. In this case, however, prior ILI results from the pipeline segments within the casings evaluated by ECDA indirect inspection methods have been substituted for LRGWUT based direct examination step. The evaluation then compares the PCM and PCM + ACVG suspected contacts to the difference between the C/S and P/S potentials and then the ILI results.

Tables F2 and F3 summarize the results of two data sets from Operator A's casing ECDA program including a total of 116 results. Both tables are in coded form to facilitate data analyses.

The coding used to describe the PCM, PCM + ACVG, and C/S-P/S potential differences are the same in Tables F2 and F3. The PCM and PCM + ACVG results include both suspected metallic and electrolytic contacts based on Operator A's indirect inspection procedure previously described in this report. In each cell where Operator A's results indicated no suspected contact (i.e., current path), a "0" has been shown. A table entry of "1" indicates that a contact may exist.

Results from the comparison of the C//S and P/S potentials are shown in the three columns under the Potential Measurement headings in Tables F2 and F3. In all cases, both measurements were not performed so no comparison according to Operator A's procedure was possible. Under the "P/S" and "C/S", headings, a "0" indicates the data was not obtained and a "1" indicates that it was. Accordingly, the coding under the column heading "Agrees with PCM/PCM + ACVG" is shown in Table F1.

Table F3 summarizes the results from a second set of 59 casings that where the PCM and CM+A-Frame along with the difference between C/S and P/S potentials as the ECDA indirect inspection step. Direct examination of some of these casings was than conducted by LRGWUT techniques. Two different LRGWUT systems were applied including those from Teletest and Guided Ultrasonics Ltd (GUL) G-3. In several cases, both LRGWUT systems were applied to the same casing thus permitting a limited comparison of the results from the two systems.

**Table F1. Code system**

| Code | Description |
|---|---|
| 0 | Both P/S and C/S potentials obtained; does not agree with indirect inspection |
| 1 | Both P/S and C/S potentials obtained; agrees with indirect inspection |
| 2 | P/S, C/S potentials, or both not obtained; cannot be compared with indirect inspection |

In Table F2, which shows indirect inspection comparisons to the prior ILI results, in the two right hand columns a "0" indcates that the ILI did not detect an anomaly in the particular casing. Similarly, a "1" indicates an ILI anomaly. Similarly in Table F3, the right hand columns summarize the LRGWUT results. In each cell containing a dash mark, no LRGWUT direct examination was conducted. Where a "0", is shown, LRGWUT data was obtained but no relevant indication was detected, whereas a "1" indicates a relevant anomaly was detected.

## Table F2.  Operator A Casing ECDA Results Summary – Indirect Inspection and ILI

| Casing Number | PCM/A-Frame Suspected Contact | | | | Potential Measurement | | | ILI Result | |
|---|---|---|---|---|---|---|---|---|---|
| | Metallic | | Electrolytic | | | | | | |
| | PCM | A-Frame | PCM | A-Frame | P/S | C/S | Agrees with PCM/A-Frame | Anomaly | Type |
| 1 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 1 | Unk |
| 2 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 3 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 4 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 5 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 6 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 7 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 8 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 9 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | |
| 10 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 11 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | |
| 12 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 13 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 14 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 15 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 16 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 17 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 18 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 19 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 20 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 21 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 22 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 23 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 24 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | |
| 25 | 0 | 0 | 0 | 1 | 0 | 1 | 2 | 0 | |
| 26 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 27 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | |
| 28 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | |
| 29 | 0 | 0 | 0 | 1 | 0 | 1 | 2 | 1 | EC |
| 30 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | EC |
| 31 | 0 | 0 | 0 | 1 | 0 | 1 | 2 | | |
| 32 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | | |
| 33 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | | |
| 34 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | | |
| 35 | 0 | 0 | 0 | 1 | 1 | 0 | 2 | 1 | EC |
| 36 | 0 | 0 | 1 | 1 | 0 | 0 | 2 | | |
| 37 | 0 | 0 | 0 | 0 | 1 | 0 | 2 | | |
| 38 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | | |
| 39 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 40 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | | |
| 41 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 42 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 43 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 44 | 0 | 0 | 1 | 0 | 1 | 1 | 0 | | |

**Table F2 (continued)**

| Casing Number | PCM/A-Frame Suspected Contact | | | | Potential Measurement | | | ILI | |
|---|---|---|---|---|---|---|---|---|---|
| | Metallic | | Electrolytic | | | | | | |
| | PCM | A-Frame | PCM | A-Frame | P/S | C/S | Agrees with PCM/A-Frame | Anomaly | Type |
| 45 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 46 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 47 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 48 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 49 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | | |
| 50 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 51 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 52 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 53 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 54 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 55 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | | |
| 56 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 57 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |
| 58 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | | |

### Table F3. Operator A Casing ECDA Results Summary – Indirect Inspection and LRGWUT

| Casing Number | PCM/A-Frame Suspected Contact | | | | Potential Measurement. | | | LRGWUT (Teletest) | LRGWUT (G-3) |
|---|---|---|---|---|---|---|---|---|---|
| | Metallic | | Electrolytic | | P/S | C/S | Agrees with PCM/A-Frame | Anomaly | Anomaly |
| | PCM | A-Frame | PCM | A-Frame | | | | | |
| 1 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 2 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 3 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 4 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 5 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | - | 0 |
| 6 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 7 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | - | 0 |
| 8 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 9 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 10 | 0 | 0 | 0 | 0 | 1 | 0 | 2 | - | - |
| 11 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 12 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 13 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 14 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 15 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | - | 0 |
| 16 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 |
| 17 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 18 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 19 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 20 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 21 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 22 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 1 |
| 23 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 24 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 25 | 0 | 0 | 0 | 1 | 1 | 0 | 2 | 0 | 0 |
| 26 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 27 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | 0 | 0 |
| 28 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 29 | 0 | 0 | 1 | 0 | 0 | 0 | 2 | - | 0 |
| 30 | 0 | 0 | 1 | 0 | 0 | 0 | 2 | 0 | 0 |
| 36 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 37 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 38 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 39 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 40 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 41 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | - |
| 42 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 43 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 44 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 45 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | - | 0 |

**Table F3 (continued)**

| Casing Number | PCM/A-Frame Suspected Contact | | | | Potential Measurement. | | | LRGWUT (Teletest) | LRGWUT (G-3) |
|---|---|---|---|---|---|---|---|---|---|
| | Metallic | | Electrolytic | | P/S | C/S | Agrees with PCM/A-Frame | Anomaly | Anomaly |
| | PCM | A-Frame | PCM | A-Frame | | | | | |
| 46 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 47 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 48 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 49 | 1 | 1 | 0 | 0 | 0 | 0 | 2 | - | 0 |
| 50 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 51 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | - | - |
| 52 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | - | - |
| 53 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 54 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 55 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 56 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 57 | 1 | 0 | 0 | 0 | 1 | 1 | 0 | - | - |
| 58 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | - | - |
| 59 | 1 | 1 | 0 | 0 | 0 | 0 | 2 | 0 | 0 |